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A cumulative list of the parts affected this month can be found in the Reader Aids section at the end of this issue.

Federal Register

Vol. 87, No. 233

Tuesday, December 6, 2022

Presidential Documents

Title 3—

The President

Memorandum of November 28, 2022

Promoting Accountability for Conflict-Related Sexual Violence

Memorandum for the Heads of Executive Departments and Agencies

By the authority vested in me as President by the Constitution and the laws of the United States of America, and in order to enhance United States policy and approach to prevent and respond to conflict-related sexual violence worldwide, it is hereby ordered as follows:

Section 1. *Policy.* Conflict-related sexual violence (CRSV) has devastating effects on individuals and communities, undermines peace and security, and prevents inclusive and sustainable development. Yet wherever conflicts or crises occur, sexual violence continues to be wielded as a tool or is a byproduct of armed conflict. Impunity for CRSV remains widespread, with accountability and justice the rare exception. For each rape reported in connection with a conflict, the United Nations estimates that 10 to 20 cases go undocumented, in part due to the impunity of perpetrators. Among the best ways to prevent CRSV worldwide are to advance global gender equity and equality and change harmful societal gender norms; prioritize prevention measures and locally-driven responses to all forms of gender-based violence, including through respect for human rights and international humanitarian law and equal protection under the law; and address impunity related to these brutal, yet often unreported, acts.

The United States does not accept CRSV as an inevitable cost of armed conflict and is committed to supporting survivors of this scourge by invoking all tools available, including legal, policy, diplomatic, and financial tools, to deter such violence, break the vicious cycle of impunity, and provide the necessary services to survivors. The United States has numerous frameworks, including laws and policies, through which to respond to and address CRSV, but more action is required to use them fully and in a manner that responds to the full scale of this problem. These efforts to address impunity and increase accountability for CRSV will complement a broader, holistic approach to preventing and responding to this scourge, which includes advancing gender equity and equality; prioritizing the immediate needs of survivors; and amplifying survivor voices in transitional justice, the provision of services, and peace and political processes.

It is the policy of the United States to fully exercise existing authorities to impose economic sanctions and implement visa restrictions in order to promote justice and accountability for acts of CRSV; devote the necessary resources to ensure regular coordination and reporting on CRSV incidents and to conduct training on CRSV issues more broadly, including to support the designation of sanctions targets; strengthen the implementation of other existing tools and authorities to promote accountability for CRSV, including the provision of United States security assistance; and broaden engagement with foreign partner governments to encourage the establishment and use of their own tools to promote justice and accountability.

Sec. 2. *Advancing Accountability for Acts of CRSV through Existing Sanctions Authorities.* (a) Executive Order 13818 of December 20, 2017 (Blocking the Property of Persons Involved in Serious Human Rights Abuse or Corruption), builds on and implements the Global Magnitsky Human Rights Accountability Act, Public Law 114–328 (the ''Act''), and authorizes the imposition of sanctions on persons, including both individuals and entities, responsible for or complicit in, or who have directly or indirectly engaged in, serious human rights abuse, as well as individuals who are or have been leaders or officials of an entity, including any government entity, that has engaged in, or which has members who have engaged in, serious human rights abuses relating to their tenure, among other things. It is the policy of the United States that an act of CRSV, committed by either state or non-state actors, may constitute a ''serious human rights abuse'' for purposes of designation under Executive Order 13818, as well as other similar authorities, and in furtherance of the policy reflected in the Act.

(b) In addition to the authorities described in subsection (a) of this section, many country-specific sanctions programs also contain criteria for the imposition of sanctions on persons engaged in or otherwise connected to activities that may include CRSV. For example, numerous sanctions programs, including country-specific programs related to Belarus, Burma, the Central African Republic, the Democratic Republic of the Congo, Iran, Libya, Mali, Nicaragua, Somalia, North Korea, the Russian Federation, South Sudan, Syria, Venezuela, the Western Balkans, and Zimbabwe, include criteria for targeting certain abuses or violations of human rights, which may include CRSV depending on specific facts and circumstances. It is the policy of the United States to promote accountability for perpetrators of acts of CRSV through relevant existing sanctions authorities, where applicable, and to ensure that these authorities are used to the fullest extent possible to target perpetrators of acts of CRSV and their enablers.

(c) I hereby direct the Secretary of State, the Secretary of the Treasury, the Attorney General, and the Director of National Intelligence to undertake the following actions, including by issuing guidance or regulations as appropriate:

(i) ensure equal consideration of and attention to acts of CRSV as the conduct supporting designation when identifying appropriate targets and compiling information necessary for the preparation of sanctions packages under applicable authorities, including those identified in this section; and

(ii) strengthen the capacity of executive departments and agencies (agencies) to collect, identify, assess, and share information on CRSV as appropriate, including by consulting with local civil society organizations, taking into account the importance of safely gathering information from survivors to support potential designations under existing sanctions authorities.

Sec. 3. *Advancing Accountability for Acts of CRSV Through Additional Measures and Authorities.* The United States is committed to using all available tools, including those pertaining to security assistance and visa eligibility, to prevent and respond to CRSV and promote accountability for perpetrators. Heads of agencies, including the Secretary of State and the Secretary of the Treasury, are directed to use existing authorities to the fullest extent possible to promote accountability for acts of CRSV, including considering acts of CRSV when assessing the potential application of existing laws and regulations, including, where appropriate, the laws known as the ''Leahy Laws'' (22 U.S.C. 2378d and 10 U.S.C. 362) and sections 7031(c) and 7048(g) of the Department of State, Foreign Operations, and Related Programs Appropriations Act, 2022 (Div. K, Public Law 117–103, as carried forward by the Continuing Appropriations Act, 2023 (Div. A, Public Law 117–180)), as well as similar provisions in future acts.

Sec. 4. *Building Coalitions of Like-Minded Nations and Engaging International Organizations in Promoting Accountability for Acts of CRSV.* Bilateral relationships with allies and partners, as well as engagement in multilateral fora and our relationships with international organizations, are critical to promote justice and accountability for acts of CRSV and bring global attention to this issue. Agencies engaged abroad shall reinforce the work they have done and amplify efforts with other nations—bilaterally and within multilateral fora—and with international organizations to broaden the number of countries willing to support accountability for acts of CRSV and to strengthen policies and locally-driven programming in multilateral institutions, including efforts to address the immediate and long-term needs of survivors, to promote accountability and justice for acts of CRSV.

Sec. 5. Definition. For the purposes of this memorandum, the term ''conflict-related sexual violence'' (CRSV) refers to incidents or patterns of sexual violence that occur in conflict or post-conflict situations with a direct or indirect link to conflict. CRSV may include rape, sexual slavery, sex trafficking, forced pregnancy, forced sterilization, and any other form of sexual violence of comparable gravity, against individuals of all gender identities. Depending on the circumstances, acts of CRSV can constitute war crimes, crimes against humanity, or acts of genocide, and therefore may constitute crimes that are punishable under international law.

Sec. 6. *General Provisions.* (a) Nothing in this memorandum shall be construed to impair or otherwise affect:

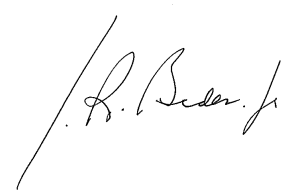
(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This memorandum shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This memorandum is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.

(d) The Secretary of State is authorized and directed to publish this memorandum in the *Federal Register*.



THE WHITE HOUSE,
Washington, November 28, 2022

[FR Doc. 2022–26604
Filed 12–5–22; 8:45 am]
Billing code 4710–10–P

Presidential Documents

Proclamation 10501 of November 30, 2022

National Impaired Driving Prevention Month, 2022

By the President of the United States of America

A Proclamation

During National Impaired Driving Prevention Month, we recommit to stopping avoidable traffic deaths and keeping America's roadways safe by driving sober, raising awareness, helping each other get home, and supporting fellow Americans who are struggling with substance use.

Over 10,000 American lives are lost to drunk and drug-impaired driving each year, accounting for nearly a third of all traffic deaths. In 2019, some 11 percent of Americans drove under the influence, including a staggering 19.6 percent of people aged 21–25—and that number has only grown since the COVID–19 pandemic began. Far too many families are left getting that gut-wrenching phone call after an accident—their worlds changed forever. Far too many passengers and pedestrians see their lives destroyed by someone else's bad decision, and far too many law enforcement officers put themselves at risk to keep impaired drivers off our roads. We owe it to them all to do everything we can to prevent future tragedies. That starts by working to reduce substance use disorders, raising awareness of the dangers of impaired driving; and investing in technologies that can help prevent crashes, injuries, and deaths.

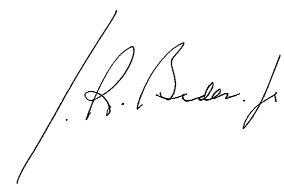
At the same time, we are promoting life-saving tools that can keep people from driving under the influence. The Bipartisan Infrastructure Law, for example, provides funds for States to develop new technologies that can detect and prevent drunk and drug-impaired driving. It also requires all new passenger motor vehicles to be equipped with crash-averting features, like automatic emergency braking and collision warnings. The Department of Transportation is also partnering with State and local agencies and nonprofits to educate the public through its *Drive Sober or Get Pulled Over* and *If You Feel Different, You Drive Different* media campaigns. We can all raise awareness within our own communities.

Starting with the American Rescue Plan, my Administration has secured billions of dollars to expand access to substance use services. We distributed $1.5 billion to fight the opioid epidemic this fall. We have asked the Congress for $24 billion more to fund prevention, treatment, and recovery programs across the country, especially in underserved communities. We are also asking the Congress for $18 billion to reduce the supply of illicit substances entering our country to help keep communities safe. And we are working to help end the stigma around addiction so more people feel free to seek the help they need.

During this holiday season especially, let us remember all those we have lost to impaired driving and take simple steps to save lives. I encourage every American to plan ahead how you will get home after drinking and to be sure that if you have used any substance you never get behind the wheel. Ride-share apps make it easier than ever to stay safe. And whenever you see loved ones or colleagues putting themselves or others at risk, step up to offer a hand. Lives depend on it.

NOW, THEREFORE, I, JOSEPH R. BIDEN JR., President of the United States of America, by virtue of the authority vested in me by the Constitution and the laws of the United States, do hereby proclaim December 2022 as National Impaired Driving Prevention Month. I urge all Americans to make responsible decisions and take appropriate measures to prevent impaired driving.

IN WITNESS WHEREOF, I have hereunto set my hand this thirtieth day of November, in the year of our Lord two thousand twenty-two, and of the Independence of the United States of America the two hundred and forty-seventh.



[FR Doc. 2022–26605
Filed 12–5–22; 8:45 am]
Billing code 3395–F3–P

Presidential Documents

Proclamation 10502 of November 30, 2022

World AIDS Day, 2022

By the President of the United States of America

A Proclamation

On World AIDS Day, we recommit to ending the HIV epidemic in the United States and around the world and rededicate ourselves to fighting the discrimination that too often keeps people with HIV from getting the services they need and living the full lives they deserve.

It was long hard to imagine, but today, we are within striking distance of eliminating HIV transmission worldwide. Thanks to the incredible dedication of scientists, activists, health care workers, caregivers, and so many others, we have made enormous progress preventing, detecting, and treating HIV; reducing case counts and AIDS-related deaths; and freeing millions of people to enjoy long, healthy lives. Still, not everyone has equal access to that care. And for the more than 38 million people around the world now living with HIV—especially members of the LGBTQI+ community, communities of color, women, and girls—a diagnosis is still life-altering. We can do better.

When I became President, we reestablished the White House Office of National AIDS Policy and released a roadmap to accelerate efforts to end the HIV epidemic in the United States by 2030. Federal agencies have committed to nearly 400 related actions, working with stakeholders across the country to make the latest advances in HIV prevention, diagnosis, and treatment available to everyone. I have asked the Congress for $850 million to increase the use of preexposure prophylaxis (PrEP), expand treatment, and fight the stigma that stops many people from getting care. We are working to remove barriers to employment, with our Armed Forces, for example, ending blanket restrictions on HIV-positive service members being deployed or commissioned. And we are calling on States to repeal or reform so-called HIV criminalization laws, which wrongly punish people for exposing others to HIV. These outdated laws have no basis in science, and they serve to discourage testing and further marginalize HIV-positive people.

Our important work to end HIV extends far beyond our borders too, with continued support for the game-changing, bipartisan President's Emergency Plan for AIDS Relief (PEPFAR). Since 2003, PEPFAR has helped at least 12 high disease-burdened countries bring HIV under control and has saved over 25 million lives. Its efforts to make HIV prevention and treatment services more accessible have achieved a 65 percent reduction in new HIV cases in males 15 to 24 years old and a 50 percent reduction in new HIV cases among females the same age since 2010. And its flagship Determined, Resilient, Empowered, AIDS-free, Mentored and Safe (DREAMS) public-private partnership has reached millions of adolescent girls and young women, reducing new HIV infections in areas where the program operates. My Administration has also pledged up to $6 billion to the Seventh Replenishment of the Global Fund to Fight AIDS, Tuberculosis, and Malaria—an initiative that has saved an estimated 50 million lives to date. I am asking other international donors to match that commitment so we can together deliver on the promise of health and well-being for millions around the world.

We still have a hard road ahead, especially in addressing racial and gender gaps in our health systems, which have long driven inequitable HIV outcomes at home and abroad. But as we today honor the 700,000 Americans and 40 million lives lost worldwide to AIDS-related illnesses over the years, we have new hope in our hearts. We finally have the scientific understanding, treatments, and tools to build an AIDS-free future where everyone—no matter who they are, where they come from, or whom they love—can get the care and respect they deserve.

NOW, THEREFORE, I, JOSEPH R. BIDEN JR., President of the United States of America, by virtue of the authority vested in me by the Constitution and the laws of the United States, do hereby proclaim December 1, 2022, as World AIDS Day. I urge the Governors of the United States and its Commonwealths and Territories, the appropriate officials of all units of government, and the American people to join the HIV community in activities to remember those who have lost their lives to AIDS and to provide support, dignity, and compassion to people with HIV.

IN WITNESS WHEREOF, I have hereunto set my hand this thirtieth day of November, in the year of our Lord two thousand twenty-two, and of the Independence of the United States of America the two hundred and forty-seventh.

[FR Doc. 2022–26606
Filed 12–5–22; 8:45 am]
Billing code 3395–F3–P

Rules and Regulations

Federal Register

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Tuesday, December 6, 2022

DEPARTMENT OF AGRICULTURE

Rural Utilities Service

7 CFR Parts 1710, 1720, and 1785

[Docket Number: RUS–21–ELECTRIC–0016]

RIN 0572–AC49

Implementing Provisions of the Agriculture Improvement Act of 2018

AGENCY: Rural Utilities Service, United States Department of Agriculture (USDA).

ACTION: Final rule; request for comments.

SUMMARY: The Agriculture Improvement Act of 2018 (2018 Farm Bill) amended several sections of the Rural Electrification Act of 1936 (RE Act) that are carried out by the Electric Program at the USDA—Rural Utilities Service (RUS). Section 6501 extends refinancing authority to RUS for loans made or guaranteed by the Secretary. Section 6503 ended the Cushion of Credit Payment Program. Section 6505 made several changes to the loan guarantee program authorized under section 313A of the RE Act. Section 6507 permits RUS to include provisions for cybersecurity and grid security improvements.

DATES:

Effective date: This rule is effective December 6, 2022.

Comment date: Comments are solicited from interested members of the public on all aspects of the rule. These comments must be submitted electronically and received on or before February 6, 2023.

ADDRESSES: Comments may be submitted on this rule using the following method:

Electronically using the Federal eRulemaking Portal: Go to *https://www.regulations.gov* and, in the lower ''Search Regulations and Federal Actions'' box, select ''Rural Utilities Service'' from the agency drop-down menu, then click on ''Submit.'' In the Docket ID column, select RUS–21–ELECTRIC–0016 to submit or view public comments and to view supporting and related materials available electronically. To submit a comment, choose the ''Comment Now!'' button. Information on using *Regulations.gov*, including instructions for accessing documents, submitting comments, and viewing the docket after the close of the comment period, is available through the site's ''User Tips'' link.

FOR FURTHER INFORMATION CONTACT: Alexis Solano, Rural Utilities Service Electric Program, Rural Development, United States Department of Agriculture, 1400 Independence Avenue SW, STOP 1568, Room 5165–S, Washington, DC 20250; Telephone: (202) 690–3407; Email *alexis.solano@usda.gov.*

SUPPLEMENTARY INFORMATION:

Discussion of Rule

Background

The 2018 Farm Bill amended several sections of the RE Act. The RE Act authorizes Rural Utilities Service's (RUS) Electric Programs (EP) to make direct loans and loan guarantees through the Federal Financing Bank. Sections 6501, 6503, 6505, and 6507 of the 2018 Farm Bill have a significant impact on the regulations for loans and loan guarantees. Section 6501 extends refinancing authority to EP for loans made or guaranteed by the Secretary. Section 6503 ends the Cushion of Credit Program by prohibiting borrowers from establishing new accounts or making new deposits into such accounts while reducing the interest paid on remaining balances. Section 6505 increased the maximum term of the bonds and notes that RUS can guarantee under the loan guarantee program authorized under section 313A of the RE Act from 20 years to 30 years. Additionally, proceeds from guaranteed bonds may be used to finance or refinance broadband loans. Finally, section 6507 addresses grid security and cybersecurity; specifically, RUS EP may now finance loans for improvements to assist in preventing or mitigating security threats. It is expected that these changes will allow borrowers more flexibility, with regard to financing new grid security and cybersecurity projects and to refinancing loans, when seeking funding from RUS.

Summary of Changes

The following is a discussion, by topic, of the changes made to comply with the 2018 Farm Bill.

Cybersecurity and Grid Security Improvements (§§ 1710.1, 1710.2, 1710.100, and 1710.106)

RUS is amending §§ 1710.1, 1710.2, and 1710.106 to include provisions for cybersecurity and grid security improvements as an eligible loan purpose for RUS EP loans as specified in section 6507 of the 2018 Farm Bill. Section 1710.1(a) is updated to expressly reflect that loans for cybersecurity and grid security improvements may now be financed; § 1710.1(b) establishes refinancing policies for loans made for these improvements and other purposes as described in § 1710.1(a). Section 1710.2 now has additional definitions, including those for cybersecurity and grid security. Section 1710.106 describes the specific uses that funds may finance regarding cybersecurity and grid security improvements as well as for purposes which funds may not be used.

This new purpose authorizes the Secretary to make or guarantee loans for cybersecurity and grid security improvements. Additionally, this new regulatory language allows borrowers greater flexibility when seeking funding from RUS to assess and mitigate the risk from known and emerging security threats and risks. Cybersecurity and grid security investments relate to resources for prevention, protection, and restoration of computers, electronic communications systems, electronic communications services, wire and electronic communication, and physical assets. The purpose of cybersecurity and grid security investments is to mitigate the risk to critical infrastructure or the financial condition of RUS's borrowers by physical means or cyber measures from intrusions, attacks, or the effects of natural or manmade disasters. Prior to the 2018 Farm Bill, RUS approved financing for cybersecurity and grid security infrastructure investment as eligible purposes when incorporated in larger infrastructure projects. With the changes outlined in section 6507, these purposes can be combined as a single project specifically designed for cybersecurity and grid security purposes. The changes contained in section 6507 explicitly incorporate cybersecurity and grid security investments as within the RUS EP's lending authority under Titles I and III of the RE Act.

Refinancing (§§ 1710.1, 1710.53, and 1710.100)

Section 6501 of the 2018 Farm Bill amended section 2 of the RE Act to authorize, subject to availability of funding for such purposes, RUS to refinance loans made or guaranteed by the Secretary under the RE Act for rural electrification, furnishing and improving electric and telephone service in rural areas, and assisting electric borrowers in implementing demand side management, energy efficiency and conservation programs, and on-grid and off-grid renewable energy systems.

RUS is amending §§ 1710.1 and 1710.100 and is adding § 1710.53 to recognize its refinancing authority as authorized by section of 6501 of the 2018 Farm Bill. Through these amendments, RUS sets the parameters for exercising said authority. Section 1710.1 is updated to briefly summarize these changes. Specifically, § 1710.1(b) includes additional language establishing refinancing policies. The new section, § 1710.53, describes the refinancing of loans and the requirements of refinancing, including the information required of borrowers seeking refinancing. Section 1710.100 now expressly includes cybersecurity and grid security as eligible projects. RUS will be able to offer new loans to pay off previous RUS loans made or guaranteed pursuant to the RE Act. New loans made under this authority must be used to repay previous loans made by RUS when the Administrator determines that such action is in the interest of rural consumers, taxpayers, rural economic development or otherwise in the public interest.

When funds become available for the refinancing of existing loans, RUS will issue a public notice specifying the amount of funds available under this authority. The notice will contain additional application procedures specific to the amount of funds available and new loan application periods related to the availability of funds. The notice may also include Administration priorities, such as directing benefits to disadvantaged communities and reducing greenhouse gas emissions. The Administrator, in setting funding priorities and application periods, may consider the amount of available funds, RUS resources, RUS priorities and policy goals, and any other factors related to the efficient operation of the agency. Such notices, at a minimum, will require applicants to provide the information set forth in § 1710.53.

Guarantees for Bonds and Notes Issued for Utility Infrastructure Purposes (§§ 1720.1, 1720.2, 1720.3, 1720.4, 1720.5, 1720.6, 1720.7, 1720.8, 1720.11, and 1720.12)

RUS is amending part 1720 to incorporate the statutory amendments as provided by section 6505 of the 2018 Farm Bill. Part 1720 implements the provisions of section 313A of the RE Act, also known as the 313A Program. Section 1720.1 describes the purpose of the regulation. Section 1720.2 will be removed and reserved as the information contained in the section is no longer necessary. In § 1720.3, definitions are added as a result of 2018 Farm Bill changes while some defined terms have been renamed for clarification. Section 1720.4 describes the changes in the general standards and requirements as RUS is now authorized to guarantee bonds or notes issued to make utility infrastructure loans. This section also now contains other changes to terms of financing and refinancing RUS loans. Section 1720.5 is updated to reflect changes in eligibility requirements. Section 1720.6 updates the application process by including requirements for credit ratings. Section 1720.7 now has additions to the application process. Section 1720.8 adds preconditions to RUS's issuance of guarantees and the release of loan funds, such as evidence of creditworthiness. Section 1720.11 adds the requirement that the Secretary may inspect the assets and facilities of the guaranteed lenders. Section 1720.12 provides additional reporting requirements of the guaranteed lenders.

Specifically, section 6505 of the 2018 Farm Bill amended section 313A of the RE Act, which authorizes RUS to guarantee bonds or notes issued to make utility infrastructure loans or refinance bonds or notes for those purposes pursuant to section 313A of the RE Act, as amended, for a term of 30 years or for another term that the Secretary determines appropriate.

RUS is also including regulatory changes that include guaranteed lenders' reporting requirements, such as the contact information for the borrowers whose notes have been pledged and terms and conditions for all notes pledged as collateral, and the development of an action plan by the guaranteed lender in the event of default. The amendments to part 1720 also allow the proceeds of bonds guaranteed under section 313A of the RE Act to be used to make broadband loans, or to refinance broadband loans, made to a borrower that has received, or is eligible to receive, a broadband loan under Title VI of the RE Act. As a result, to the extent that the proceeds of bonds guaranteed under section 313A are to be used to fund or refinance broadband loans that were not made by RUS (''Non-RUS Broadband Loans''), such proceeds may only be used for Non-RUS Broadband Loans that would meet the amended eligibility requirements of Title VI of the RE Act pursuant to the 2018 Farm Bill. The 2018 Farm Bill also modified the 313A Program to allow the proceeds of guaranteed loans to be used by the Guaranteed Lender to fund projects for the generation of electricity. Furthermore, it has increased the maximum term of the bonds or notes that RUS can guarantee from 20 years to 30 years.

Cushion of Credit Payment Program (§§ 1785.66, 1785.68, 1785.69, and 1785.70)

RUS is amending §§ 1785.66 and 1785.68 through 1785.70 to discontinue cushion of credit accounts and make other changes to the existing accounts as specified in section 6503 of the 2018 Farm Bill. Section 1785.66 describes the discontinuation of the Cushion of Credit Payment Program, which occurred on the date of enactment of the 2018 Farm Bill, December 20, 2018. Section 1785.68 provides specific information on the reduction of interest rates. Section 1785.69 shows the changes in the computations of the interest paid to these accounts. Section 1785.70 includes additional information about drawing down balances by the borrower and ending the Cushion of Credit Payment Program when all balances have reached zero.

Prior to the 2018 Farm Bill, each borrower who made a payment after October 1, 1987, in excess of the required amount due on a RUS note was provided with a cushion of credit account. All payments on these notes which were in excess of required payments and not otherwise designated were deposited in the borrower's cushion of credit account. This account bore an interest rate of 5 percent per annum. Beginning on December 20, 2018, the date the 2018 Farm Bill became law, no new deposits to the program were allowed. From the date of enactment until September 30, 2020, cushion of credit balance holders were permitted to transfer money from their cushion of credit accounts for the purpose of prepaying their RUS debt or Federal Financing Bank debt without a prepayment penalty. Existing balances continued to earn 5 percent interest until September 30, 2020. This interest rate decreased to 4 percent on October 1, 2020. Beginning on October 1, 2021, interest paid on fund balances will be fixed at a floating 1-year Treasury rate. These changes were made to § 1785.69. RUS will no longer have to maintain the cushion of credit accounts after the remaining balances are depleted. This change will result in savings to the Government in an amount equal to the amount of interest that would have been paid by the Government to the account holders had this section of the 2018 Farm Bill not been implemented.

Regulatory Analysis

Executive Order 12866 and 13563

Executive Orders 12866 and 13563 direct agencies to assess all costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches to maximize net benefits (including potential economic, environmental, public health and safety effects, distributive impacts, and equity). Executive Order 13563 emphasizes the importance of quantifying both costs and benefits, of reducing costs, of harmonizing rules, and of promoting flexibility.

This rule has been determined to be significant and was reviewed by the Office of Management and Budget (OMB) under Executive Order 12866. In accordance with Executive Order 12866, an Economic Impact Analysis was completed, outlining the costs and benefits of implementing this program in rural America. The complete analysis is available from *Regulations.gov* by searching for Docket number RUS–21–ELECTRIC–0016.

Unfunded Mandates

This final rule contains no Federal mandates (under the regulatory provision of Title II of the Unfunded Mandates Reform Act of 1995) for State, local, and tribal governments, or the private sector. Thus, this final rule is not subject to the requirements of section 202 and 205 of the Unfunded Mandates Reform Act.

National Environmental Policy Act

This final rule has been reviewed in accordance with 7 CFR part 1970 (''Environmental Policies and Procedures''). The Agency has determined that: (1) this action of implementing this rule meets the criteria established in 7 CFR 1970.53(f); (2) no extraordinary circumstances exist; and (3) the action is not ''connected'' to other actions with potentially significant impacts, is not considered a ''cumulative action,'' and is not precluded by 40 CFR 1506.1. Therefore, the Agency has determined that the action does not have a significant effect on the human environment, and therefore neither an Environmental Assessment nor an Environmental Impact Statement is required. However, individual actions assisted with financing described in this rule are subject to the requirements of the National Environmental Policy Act, 7 CFR part 1970 (Rural Development's Environmental Policies and Procedures), and associated laws and authorities, including the National Historic Preservation Act.

Executive Order 12988, Civil Justice Reform

This rule has been reviewed under Executive Order 12988. In accordance with this rule: (1) unless otherwise specifically provided, all State and local laws that conflict with this rule will be preempted; (2) no retroactive effect will be given to this rule except as specifically prescribed in the rule; and (3) administrative proceedings of the National Appeals Division of the Department of Agriculture (7 CFR part 11) must be exhausted before bringing suit in court that challenges action taken under this rule.

Executive Order 13132, Federalism

The policies contained in this rule do not have any substantial direct effect on 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. Nor does this final rule impose substantial direct compliance costs on state and local governments. Therefore, consultation with the states is not required.

Administrative Procedure Act and Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601–602) (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act (''APA'') or any other statute. The APA exempts from notice and comment requirements rules ''relating to agency management or personnel or to public property, loans, grants, benefits, or contracts'' (5 U.S.C. 553(a)(2)). Because this rule is a matter relating to public loans, it is exempt from the APA's notice and comment requirements and therefore from the RFA's analysis requirements. Accordingly, an RFA analysis has not been prepared for this rule.

Executive Order 12372, Intergovernmental Consultation

This rule is excluded from the scope of Executive Order 12372, Intergovernmental Consultation, which may require a consultation with State and local officials. See the final rule related notice entitled ''Department Programs and Activities Excluded from Executive Order 12372'' (50 FR 47034) advising that RUS loans and loan guarantees were not covered by Executive Order 12372.

Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

This rule has been reviewed in accordance with the requirements of Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments.'' Executive Order 13175 requires Federal agencies to consult and coordinate with Tribes on a government-to-government basis on policies that have tribal implications, including regulations, legislative comments or proposed legislation, and other policy statements or actions that have substantial direct effects 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.

The Office of Tribal Relations has reviewed this rule and finds that it does have tribal implications that require clarification under E.O. 13175. The Agency held Virtual Tribal Consultation events in March of 2021 and April of 2022 with tribal officials as to the need for Federal standards and any alternatives that would limit the scope of Federal standards or otherwise preserve the prerogatives and authority of Indian tribes, pursuant to E.O. 13175, sec. 3(c)(3). Comments on tribal implications received through consultations were deemed, after discussion with the Office of Tribal Relations (OTR), outside the purview of this regulation and OTR will coordinate with Rural Utilities Service to utilize the currently underway RUS Regulatory Streamlining process to clarify the concerns of tribal eligibility, necessary tribal permissions, and tribal law compliance that were raised during the two consultation sessions. Should a tribe request consultation in the future, Rural Utilities Service will work with the USDA Office of Tribal Relations to ensure that meaningful consultation occurs. If tribal leaders are interested in consulting with RUS, they are encouraged to contact USDA's Office of Tribal Relations at *Tribal.Relations@usda.gov* or Rural Development's Native American Coordinator at: *AIAN@usda.gov* to request such a consultation.

Assistance Listing

The Assistance Listing (formerly Catalog of Federal Domestic Assistance or CFDA) number for the program impacted by this action is 10.850, Rural Electrification Loans and Loan Guarantees. A complete list of Assistance Listings is available at *https://sam.gov/content/assistance-listings.*

Paperwork Reduction Act

This rule contains no new reporting or recordkeeping burdens under OMB control number 0572–0032 that would require approval under the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35).

E-Government Act Compliance

Rural Development is committed to the E-Government Act, which requires Government agencies in general to provide the public the option of submitting information or transacting business electronically to the maximum extent possible.

Civil Rights Impact Analysis

Rural Development has reviewed this rule in accordance with USDA Regulation 4300–4, ''Civil Rights Impact Analysis,'' to identify any major civil rights impacts the rule might have on program participants on the basis of age, race, color, national origin, sex, or disability. Based on the review and analysis of the rule and available data, application submission, and eligibility criteria, issuance of this final rule is not likely to adversely nor disproportionately impact low and moderate-income populations, minority populations, women, Indian Tribes, or persons with disability, by virtue of their race, color, national origin, sex, age, disability, or marital or familial status.

USDA Non-Discrimination Policy

In accordance with Federal civil rights laws and U.S. Department of Agriculture (USDA) civil rights regulations and policies, the USDA, its Mission Areas, agencies, staff offices, employees, and institutions participating in or administering USDA programs are prohibited from discriminating based on race, color, national origin, religion, sex, gender identity (including gender expression), sexual orientation, disability, age, marital status, family/parental status, income derived from a public assistance program, political beliefs, or reprisal or retaliation for prior civil rights activity, in any program or activity conducted or funded by USDA (not all bases apply to all programs). Remedies and complaint filing deadlines vary by program or incident. 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, audiotape, 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, a complainant should complete a Form AD–3027, *USDA Program Discrimination Complaint Form,* which can be obtained online at *https://www.usda.gov/sites/default/files/documents/usda-program-discrimination-complaint-form.pdf,* from any USDA office, by calling (866) 632–9992, or by writing 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 an 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.*

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List of Subjects

7 CFR Part 1710

Electric power, Energy, Grant program, Loan program–energy, Reporting and recordkeeping requirements, Rural areas.

7 CFR Part 1720

Loan programs-energy, Reporting and recordkeeping requirements, Rural areas.

7 CFR Part 1785

Electric power, Loan programs-communications, Loan programs-energy, Rural areas, Telephone.

For the reasons set forth in the preamble, RUS amends 7 CFR parts 1710, 1720, and 1785 as follows:

PART 1710—GENERAL AND PRE-LOAN POLICIES AND PROCEDURES COMMON TO ELECTRIC LOANS AND GUARANTEES

■ 1. The authority citation for part 1710 continues to read as follows:

Authority: 7 U.S.C. 901 *et seq.,* 1921 *et seq.,* and 6941 *et seq.*

■ 2. Revise § 1710.1 to read as follows:

§ 1710.1 General statement.

(a) This part establishes general and pre-loan policies and requirements that apply to both insured and guaranteed loans to finance the construction and improvement of electric facilities in rural areas, including generation, transmission, distribution facilities, and cybersecurity and grid security needs.

(b) This part also establishes general and pre-loan refinancing policies and requirements that apply to the refinancing of loans made or guaranteed for the purpose of rural electrification, furnishing and improving electric service in rural areas, and assisting electric borrowers to implement demand side management, energy efficiency and conservation programs, on-grid, and off-grid renewable energy systems, and cybersecurity and grid security improvements.

(c) Additional pre-loan policies, procedures, and requirements that apply specifically to guaranteed and insured loans are set forth elsewhere:

(1) For guaranteed loans in 7 CFR part 1712 and RUS Bulletins 20–22, 60–10, 86–3, 105–5, and 111–3, or the successors to these bulletins; and

(2) For insured loans in 7 CFR part 1714 and in RUS Bulletins 60–10, 86–3, 105–5, and 111–3, or the successors to these bulletins.

(d) This part supersedes those portions of the following RUS Bulletins and supplements that are in conflict with this part including but not necessarily limited to the following:

(1) 20–5 Extensions of Payments of Principal and Interest.

(2) 20–20 Deferment of Principal Repayments for Investment in Supplemental Lending Institutions.

(3) 20–22 Guarantee of Loans for Bulk Power Supply Facilities.

(4) 20–23 Section 12 Extensions for Energy Resources Conservation Loans.

(5) 60–10 Construction Work Plans, Electric Distribution Systems.

(6) 86–3 Headquarters Facilities for Electric Borrowers.

(7) 105–5 Financial Forecast-Electric Distribution Systems.

(8) 111–3 Power Supply Surveys.

(9) 120–1 Development, Approval, and Use of Power Requirements Studies.

■ 3. Amend § 1710.2 by adding to paragraph (a) the definition ''Cybersecurity and grid security improvements'' in alphabetical order to read as follows:

§ 1710.2 Definitions and rules of construction.

(a) * * *

Cybersecurity and grid security improvements means:

(i) Investment in the development, expansion, and modernization of rural utility infrastructure that addresses known and emerging cybersecurity and grid security risks. This definition incorporates both cybersecurity and grid security as one concept. The cybersecurity component of the definition includes measures and investments designed to prevent damage to, otherwise protect, or restore computers and computer systems, industrial control systems/operational technology, electronic communications systems, electronic communications services, wire, and all other forms electronic communication including information contained therein. Rural utilities often utilize cybersecurity measures and investments to ensure service availability, system integrity, user authentication, confidentiality, and nonrepudiation, related to the services.

(ii) The grid security component of this definition, includes measures and investments made to protect a utility's infrastructure reliability and resiliency against both natural impacts and man-made physical attacks or intrusions by individuals or groups intent on damaging, destroying, disrupting, or removing components of utility infrastructure or threatening to damage utility infrastructure. Measures considered for RUS financing include, but are not limited to, fire prevention, physical barriers, remote sensing equipment, monitoring physical assets, security cameras, security vehicles, information and operational technology cybersecurity measures, control systems cybersecurity monitoring technologies, fire prevention devices and sensors and other investments which serve the purpose of protecting assets and maintaining the reliability of rural utility systems.

* * * * *

■ 4. Add § 1710.53 to read as follows:

§ 1710.53 Refinancing.

(a) *General.* (1) Subject to the availability of funds for such purpose, RUS may use loan funds to refinance prior loans made or guaranteed under the RE Act, as amended, (7 U.S.C. 902(a)). Such refinancing must be in the interest of rural consumers, taxpayers, rural economic development or otherwise in the public interest, as determined by the Administrator.

(2) The Secretary's authority to make loans for refinancing under this section is in addition to any other authority granted to the Secretary to make or modify loans under the RE Act or any other statutory authority.

(3) Nothing in this section changes the policies or standards set forth in 7 CFR part 1717, subpart Y, or the terms and conditions of the agreements entered into between RUS and FFB or the notes issued to RUS or FFB in connection with RUS or FFB loans.

(4) When funds are made available under this section, RUS will issue a public notice in the **Federal Register** specifying the amount of funds available under this section. The notice will contain additional application procedures specific to the amount and type of funding available and new loan application periods related to the availability of funds. The notice may also include Administration priorities, such as directing benefits to disadvantaged communities and reducing greenhouse gas emissions. The Administrator, in setting funding priorities and application periods, may consider the amount of available funds, RUS resources, RUS priorities and policy goals, and any other factors related to the efficient operation of the agency.

(b) *Definitions.* For the purpose of this section, the following terms have the following meanings. Terms not defined here are defined in § 1710.2. When the definitions provided in this section conflict with any other definition applicable to RUS Electric Program regulations in this chapter, including § 1710.2, the definition of this section will control only as it relates to refinancing under this section.

Advance means advance or advances of loan funds made by RUS to the borrower pursuant to the terms and conditions in the loan documents.

Agency means the Rural Utilities Service or its successor.

Conditional commitment letter means the notification issued by the Administrator to an eligible entity advising it of the estimated terms, conditions, and amount of the new loan.

Eligible entity means an RUS Electric Program borrower with an unpaid and outstanding FFB loan or RUS loan.

FFB means the Federal Financing Bank.

FFB loan means a loan made by FFB and guaranteed by RUS pursuant to the RE Act for electric purposes.

RUS loan means a loan made by the RUS under the RE Act for electric purposes.

(c) *Loan purpose.* Proceeds of loans made under this section may be used to:

(1) Prepay all outstanding amounts owed on an FFB or RUS loan or one or more advances made under such loan; and

(2) Pay any applicable prepayment premium, fee, or expense related to the eligible RUS or FFB loan being refinanced.

(d) *Eligibility requirements*—(1) *Eligible entity.* Loans under this section may only be made to an eligible entity for the purposes indicated in paragraph (c) of this section.

(2) *Eligible loans for refinancing.* Only FFB loans and RUS loans as defined in this section are eligible for refinancing under this section.

(e) *Allocation of funds under this section.* Unless prohibited by congressional appropriation or statute, in allocating the funds available to RUS under its lending authority, the Administrator may determine, on a programmatic or case by case basis, that other RE Act loan purposes take priority over refinancing. The Administrator may, but is not limited to, consider the following factors in making this determination:

(1) The overall availability of funding compared to anticipated loan demand;

(2) The best interests of rural consumers;

(3) The protection of the Government's financial interest in existing loans and collateral; and

(4) Broader policy objectives, including directing benefits to disadvantaged communities, reducing greenhouse gas emissions, and other priorities of the Secretary of Agriculture.

(f) *Application process.* (1) When funds are available, the RUS will publish a notice identifying the amount and type of funds available for refinancing for the funding period in total and per applicant. The notice will identify the priorities established by the Agency for the use of the available funds. Borrowers seeking to refinance RUS loans or FFB loans will be required to submit, at a minimum, the following information:

(i) Borrower reference number;

(ii) Note designation;

(iii) Rural Electric Telephone (RET) Advance loan account number;

(iv) FFB complete identifier for an FFB loan;

(v) Date(s) of advance;

(vi) Interest rate;

(vii) Principal outstanding;

(viii) Current final maturity date;

(ix) Short narrative explaining how the proposed refinancing would be in the interest of rural consumers, taxpayers, rural economic development or otherwise in the public interest; and

(x) The requested final maturity date for the new loan. The requested final maturity date must be for a period not to exceed the maximum maturity date allowed by statute, regulation, or applicable notice. An eligible entity must submit a certification that the remaining useful life of its electric system is equal to or exceeds the new requested final maturity date and, that the requested final maturity date does not exceed the term of its wholesale power contract with its members or with its generation and transmission supplier (where applicable).

(2) The Agency reserves the right to offer a loan under this section with a maturity date that varies from the requested date. Unless the Administrator makes a specific determination to the contrary, the Electric Program will not approve a new loan that includes a final maturity date that exceeds the remaining useful life of its electric system or any applicable wholesale power contract term.

(3) On a case-by-case basis, as necessary, the Administrator may approve a new loan that includes a final maturity that exceeds the remaining useful life of the applicant's electric system or applicable wholesale power contract term provided the Administrator finds that the requirements contained in § 1710.151 are satisfied, the new loan is feasible under § 1710.151(b), and such action addresses critical environmental or consumer needs.

(g) *Loan requirements.* (1) All refinancing loans made under this section must be in the interest of rural consumers, taxpayers, rural economic development, or otherwise in the public interest.

(2) All refinancing loans made under this section must be feasible as determined by RUS based on the financial condition of the borrower and the borrower's ability to repay and all loans must be adequately secured, as determined by RUS.

(3) Borrowers will be required to execute new legal documents, including a new note, loan contract, and security documents as necessary.

(4) Refinancing loans made under this section will generally be considered categorical exclusions for the purpose of environmental reviews because environmental reviews have previously been completed for the FFB loans or RUS loans being refinanced.

(h) *New loan terms.* (1) Interest on advances made on loans made under this section will be at the interest rate available on the date of the advance for the new loan used to refinance the prior outstanding loan and any related premium, fee, or expense.

(2) An eligible entity must propose a maturity date for the new loan not to exceed the maturity prescribed by this section, a funding notice, or thirty-five (35) years, whichever is shortest.

(3) An eligible entity may be given the option of applying the proceeds of an advance made on the new loan to cover any applicable prepayment premium, fee, or other expense.

(4) If the prepayment premiums are to be financed by the new loan, the maximum principal amount of the note will be increased in an amount sufficient to cover such prepayment premiums in full.

(5) Provided such waiver is not inconsistent with applicable law or the terms and conditions of the notes previously issued to RUS or FFB, the Administrator may, on a case-by-case basis, waive or modify the requirements set forth in this paragraph (h), if in the Administrator's judgment, it is necessary to implement the intent of the authorizing statute and is in the best financial interest of the Government.

■ 5. Revise § 1700.100 to read as follows:

§ 1710.100 General.

(a) RUS makes loans and loan guarantees to finance the construction of electric distribution, transmission, and generation facilities, including system improvements and replacements, and cybersecurity and grid security improvements, required to furnish and improve electric service in rural areas, and for demand side management, efficiency, and energy conservation programs, and on-grid and off-grid renewable energy systems. In certain limited circumstances, and at the discretion of the Administrator, RUS may finance selected operating expenses of its borrowers. Loans made or guaranteed by the Administrator will be made in conformance with the RE Act, as amended (7 U.S.C. 901 *et seq.*), and this chapter. The Administrator's decision to provide financing for selecting operating expenses may include, but is not limited to the following factors:

(1) The overall availability of funding compared to anticipated loan demand;

(2) The best interests of rural consumers;

(3) The protection of the Government's financial interest in existing loans and collateral; and

(4) Broader policy objectives, including directing benefits to disadvantaged communities, reducing greenhouse gas emissions, and other priorities of the Secretary of Agriculture.

(b) RUS provides technical assistance to borrowers to aid the development or improvement of rural electric service and to protect RUS' loan security. Additional information is available at *https://rd.usda.gov/programs-services/electric-programs.*

(c) Provided funds are available for such purpose, RUS may refinance, as provided in § 1710.53, RUS Electric Program loans made or guaranteed for the purpose of furnishing and improving electric service in rural areas, and for the purpose of assisting electric borrowers to implement demand side management, energy efficiency and conservation programs, on-grid and off-grid renewable energy systems, and cybersecurity and grid security improvements.

■ 6. Amend § 1710.106 by adding paragraphs (a)(7) and (8) and revising paragraphs (c)(1) and (e) to read as follows:

§ 1710.106 Uses of loan funds.

(a) * * *

(7) *Cybersecurity and grid security.* Eligible cybersecurity and grid security improvements.

(8) *Smart grid infrastructure.* The purchase, installation, improvements, and investments in assets needed for a robust smart grid infrastructure capability that enables the utility to operate efficiently, improve its reliability, and enhance its ability to recover from disasters, physical or cyber-attacks, carry out energy efficiency and demand side management activities, and implement renewable energy technologies and cybersecurity and grid security strategies.

(i) Smart grid, grid security, or cybersecurity infrastructure financed under this section must relate to one or more electric utility or energy efficiency purpose. Loan proceeds under this section may not be used to solely finance retail broadband services.

(ii) Notwithstanding paragraph (a)(8)(i) of this section, a borrower is permitted to use up to 10 percent of the amount provided under this subpart to construct, improve, or acquire broadband infrastructure related to the project financed, subject to the requirements of 7 CFR part 1980, subpart M.

* * * * *

(c) * * *

(1) Electric facilities, equipment, appliances, or wiring located inside the premises of the consumer, except for measures related to grid security, cybersecurity, or assets financed pursuant to an eligible EE Program, and qualifying items included in a loan for demand side management or energy resource conservation programs, or renewable energy systems.

* * * * *

(e)(1) If, in the sole discretion of the Administrator, the amount authorized for lending for municipal rate loans, hardship rate loans, and loan guarantees in a fiscal year is substantially less than the total amount eligible for RUS financing, RUS may limit the size, type, or purpose of loans approved during the fiscal year. Depending on the amount of the shortfall between the amount authorized for lending and the loan application inventory on hand for each type of loan, RUS may either reduce the amount on an equal proportion basis for all applicants for that type of loan based on the amount of funds for which the applicant is eligible or may shorten the loan period for which funding will be approved to less than the maximum of 4 years. All applications for the same type of loan approved during a fiscal year will be treated in the same manner, except that RUS will not limit funding to any borrower requesting a RUS loan or loan guarantee of $1 million or less. Should a shortfall or urgent need related to cybersecurity, grid security, or statutory preference become evident during a fiscal year, the Administrator may announce priorities in a public notice for utilizing available funds for the balance of the fiscal year.

(2) If RUS limits the amount of loan funds approved for borrowers, the Administrator shall provide public notice to all electric borrowers as early as possible in the fiscal year of the manner in which funding will be limited. The portion of the loan application that is not funded during that fiscal year may, at the borrower's option, be treated as a second loan application received by RUS at a later date. This date will be determined by RUS in the same manner for all affected loans and will be based on the availability of loan funds. The second loan application shall be considered complete except that the borrower must submit a certification from a duly authorized corporate official stating that funds are still needed for loan purposes specified in the original application and must notify RUS of any changes in its circumstances that materially affects the information contained in the original loan application or the primary support documents. See § 1710.401(f).

* * * * *

PART 1720—GUARANTEES FOR BONDS AND NOTES ISSUED FOR UTILITY INFRASTRUCTURE PURPOSES

■ 7. The authority citation for part 1720 continues to read as follows:

Authority: 7 U.S.C. 901 *et seq.;* 7 U.S.C. 940C.

■ 8. Revise the heading for part 1720 to read as set forth above.

■ 9. Revise § 1720.1 to read as follows:

§ 1720.1 Purpose.

This part prescribes policies and procedures implementing a guarantee program for bonds and notes issued for utility infrastructure purposes authorized by section 313A of the Rural Electrification Act of 1936 (7 U.S.C. 940c–1).

§ 1720.2 [Removed and Reserved]

■ 10. Remove and reserve § 1720.2.

■ 11. Revise § 1720.3 to read as follows:

§ 1720.3 Definitions.

For the purpose of this part:

Administrator means the Administrator of RUS.

Applicant means a bank or other lending institution organized as a private, not-for-profit cooperative association, or otherwise on a non-profit basis, that is applying for RUS to guarantee a bond or note under this part.

Bond documents means the guarantee, guarantee agreement, Pledge Agreement, and all other instruments and documentation pertaining to the issuance of the guaranteed bonds.

Criticized loan means a loan that has borrower risk ratings that have been categorized as ''special mention,'' substandard,'' ''doubtful'', or ''loss'', or any comparable categorization as described in the guaranteed lender's most recent audited financial statements.

Eligible instrument means a note or bond of a borrower payable or registered to, or to the order of, the guaranteed lender and for which:

(1) No default has occurred in the payment of principal or interest in accordance with the terms of such note or bond that is continuing beyond the contractual grace period (if any) provided in such note or bond for such payment;

(2) No ''event of default'', as defined in such note or bond (or in any instrument creating a security interest in favor of the guaranteed lender, in respect of such note or bond), shall exist that has resulted in the exercise of any right or remedy described in such note or bond (or in any such instrument);

(3) Such note or bond is not classified by the guaranteed lender as ''non-performing, criticized or impaired'' (or any comparable classification, as determined by RUS) under generally accepted accounting principles in the United States or this part;

(4) Such note or bond is free and clear of all liens other than the lien created by the guaranteed lender's pledge of such security to RUS under the Pledge Agreement;

(5) Such note or bond is not a restructured loan;

(6) Such note or bond is not unsecured debt; and

(7) The amount of generation or transmission loans does not exceed the maximum amount allowed by RUS based on RUS's sole determination of certain factors including, but not limited to, account risk, collateral quality, and collateral quantity.

Eligible loan means a loan that a guaranteed lender extends to a borrower for up to 100 percent of the cost of eligible utility infrastructure purposes consistent with the RE Act.

Federal Financing Bank (FFB) refers to the Government corporation and instrumentality of the United States of America under the general supervision of the Secretary of the Treasury established by the Federal Financing Bank Act of 1973 (12 U.S.C. 2281 *et seq.*).

Guarantee means the written agreement between the Secretary and a guaranteed lender, pursuant to which the Secretary guarantees full repayment of the principal, interest, and call premium, if any, on a guaranteed bond.

Guarantee agreement means the written agreement between the Secretary and the guaranteed lender which sets forth the terms and conditions of the guarantee.

Guaranteed bond means any bond, note, debenture, or other debt obligation issued by a guaranteed lender on a fixed or variable rate basis, and approved by the Secretary for a guarantee under this part.

Guaranteed bondholder means any investor in a guaranteed bond.

Guaranteed lender means an applicant that has been approved for a guarantee under this part.

Leveraging data means the cumulative change in the guaranteed lender's outstanding loans since the filing of the guaranteed lender's last Form 10–Q or Form 10–K or financial statements, as applicable.

Loan means any credit instrument that the guaranteed lender extends to a borrower for any utility infrastructure purpose eligible under the RE Act, including loans as set forth in section 4 of the RE Act for electricity transmission lines and distribution systems, loans as set forth in section 201 of the RE Act for telephone lines, facilities, and systems, and loans as set forth in Title VI of the RE Act for broadband systems.

Loan documents means the loan agreement and all other instruments and documentation between the guaranteed lender and the borrower evidencing the making, disbursing, securing, collecting, or otherwise administering of a loan.

Pledge Agreement means the written agreement among the Secretary, the guaranteed lender, and a collateral agent, which sets forth the terms and conditions of the guaranteed lender's pledge of eligible instruments as collateral.

Pledged collateral means the following items pledged to RUS by the guaranteed lender as security for the guaranteed lender's repayment of a guaranteed bond:

(1)(i) The pledged instruments and the certificates representing the pledged instruments;

(ii) All payments of principal or interest, cash, instruments, and other property from time to time received, receivable, or otherwise distributed in respect of, in exchange for, and all other proceeds received in respect of, the pledged instruments;

(iii) All rights and privileges of the guaranteed lender with respect to the pledged instruments; and

(iv) All other proceeds of any of the foregoing; and

(2) Any property, including cash and certain permitted investments, that are pledged by the guaranteed lender as security for the repayment of a guaranteed bond.

Pledged instruments means the eligible instruments pledged by the guaranteed lender to RUS as security for the repayment of a guaranteed bond.

Program or *313A Program* means the guarantee program for bonds and notes issued for utility infrastructure purposes authorized by section 313A of the RE Act as amended.

Rating agency means a bond rating agency identified by the Securities and Exchange Commission as a nationally recognized statistical rating organization.

RE Act means the Rural Electrification Act of 1936 (7 U.S.C. 901 *et seq.*) as amended.

RUS means the Rural Utilities Service, a Rural Development agency of the U.S. Department of Agriculture.

Secretary means the Secretary of Agriculture acting through the Administrator of RUS.

Subsidy amount means the amount of budget authority sufficient to cover the estimated long-term cost to the Federal Government of a guarantee, calculated on a net present value basis, excluding administrative costs and any incidental effects on Government receipts or outlays, in accordance with the provisions of the Federal Credit Reform Act of 1990 (2 U.S.C. 661 *et seq.*).

Utility infrastructure means equipment, systems, facilities, or other assets used to deliver electric, telephone, or broadband related services to consumers or to entities serving consumers.

■ 12. Amend § 1720.4 by revising paragraphs (a)(1), (b), (c), and (e) to read as follows:

§ 1720.4 General standards.

(a) * * *

(1) The proceeds of the guaranteed bonds will be used by the guaranteed lender to make loans to borrowers for utility infrastructure purposes eligible for assistance under this chapter, or to refinance, subject to certain limitations, bonds or notes previously issued by the guaranteed lender for such purposes to a borrower that has at any time received, or is eligible to receive, a loan under the RE Act;

* * * * *

(b) During the term of the guarantee, the guaranteed lender shall:

(1) Limit cash patronage refunds for guaranteed lenders having a credit rating below the level proscribed by the agency in its funding notice or below investment grade or comparable level on its senior secured debt without regard to the guarantee. For such guaranteed lenders, cash patronage refunds are limited to five percent of the total patronage refund eligible. The limit on patronage refunds must be maintained until the credit rating is restored to the level proscribed by RUS in its funding notice or to investment grade or above. For those guaranteed lenders subject to patronage limitations, equity securities issued as part of the patronage refund shall not be redeemable in cash during the term of any part of the guarantee, and the guaranteed lender shall not issue any dividends on any class of equity securities during the term of the guarantee.

(2) Maintain sufficient collateral secured by a perfected lien equal to the principal amount outstanding. Collateral shall be in the form of specific and identifiable unpledged securities equal to the value of the guaranteed amount plus sufficient margin to cover potential costs, fees, and expenses which may arise in the event of a default. In the case of a guaranteed lender's default, the U.S. Government's claim shall not be subordinated to the claims of other creditors, and the indenture must provide that in the event of default, the Government has the sole right to the pledged instruments. The Secretary has discretion to require additional collateral at any time should circumstances warrant.

(c) The final maturity of the guaranteed bonds shall not exceed 30 years.

* * * * *

(e) The Secretary shall guarantee payments on guaranteed bonds in such forms and on such terms and conditions and subject to such covenants, representations, warranties, and requirements (including requirements for audits) as determined appropriate for satisfying the requirements of this part. The Secretary shall require the guaranteed lender to enter into a guarantee agreement to evidence its acceptance of the foregoing. Any guarantee issued under this part shall be made in a separate and distinct offering.

■ 13. Amend § 1720.5 by revising paragraphs (a)(2) and (b)(2) to read as follows:

§ 1720.5 Eligibility criteria.

(a) * * *

(2) Able to demonstrate to the Secretary that it possesses the appropriate expertise, experience, and qualifications to make loans for utility infrastructure purposes.

(b) * * *

(2) The guaranteed bonds to be issued by the guaranteed lender must receive an underlying investment grade rating from a rating agency, without regard to the guarantee. If an applicant has no outstanding RUS guarantees or has outstanding aggregate guarantees of less than $25 million, the Administrator may prescribe in advance by notice an alternate method for the guaranteed lender to demonstrate creditworthiness.

* * * * *

■ 14. Amend § 1720.6 by revising paragraphs (a)(4), (6), and (7) to read as follows:

§ 1720.6 Application process.

(a) * * *

(4) A pro-forma financial statement and cash flow projection or business plan including detailed assumptions for the next five years, demonstrating that there is reasonable assurance that the applicant will be able to repay the

guaranteed bonds in accordance with their terms;

* * * * *

(6) Evidence of having been assigned an investment grade rating on the debt obligations for which it is seeking the guarantee, without regard to the guarantee or such other evidence of creditworthiness as required by the Administrator under § 1720.5(b)(2);

(7) Evidence of a credit rating, from a rating agency, on its senior secured debt, its corporate credit rating, or such other evidence of creditworthiness as required by the Administrator under § 1720.5(b)(2); and

* * * * *

■ 15. Amend § 1720.7 by revising paragraphs (b)(4) through (6), adding paragraph (b)(7), and revising paragraph (c) to read as follows:

§ 1720.7 Application evaluation.

* * * * *

(b) * * *

(4) The extent to which the applicant is subject to supervision, examination, and safety and soundness regulation by an independent Federal or state agency;

(5) The extent of concentration of financial risk that RUS may have resulting from previous guarantees made under section 313A of the RE Act;

(6) The extent to which providing the guarantee to the applicant will help reduce the cost and/or increase the supply of credit to rural America, or generate other economic benefits, including the amount of fee income available to be deposited into the Rural Economic Development Subaccount, maintained under section 313(b)(2)(A) of the RE Act (7 U.S.C. 940c(b)(2)(A)), after payment of the subsidy amount; and

(7) The geographic or economic distribution of funds made available through this program or use of such funds to advance rural development infrastructure goals.

(c) *Independent assessment.* Before a guarantee decision is made by the Secretary, the Secretary shall request that the Federal Financing Bank review the adequacy of the determination by the rating agency required under § 1720.5(b)(2) as to whether the bond or note to be issued would be below investment grade without the guarantee, or such other evidence of creditworthiness as may be required by the Administrator under § 1720.5(b)(2).

* * * * *

■ 16. Amend § 1720.8 by:

■ a. Redesignating paragraphs (a)(6) through (9) as paragraphs (a)(7) through (10);

■ b. Adding a new paragraph (a)(6);

■ c. Revising newly redesignated paragraphs (c)(9) and (10); and

■ d. Adding paragraph (c).

The additions and revisions read as follows:

§ 1720.8 Issuance of the guarantee.

(a) * * *

(6) Outside legal counsel to the applicant, satisfactory to the Secretary, must furnish an opinion satisfactory to the Secretary that the Pledge Agreement creates in RUS's favor a valid perfected and enforceable security interest in the eligible securities pledged to RUS under the Pledge Agreement;

* * * * *

(9) The applicant will provide evidence of a credit rating on its senior secured debt or its corporate credit rating, as applicable, without regard to the guarantee and satisfactory to the Secretary; and

(10) Certification by the Chairman of the Board and the Chief Executive Officer of the applicant (or other senior management acceptable to the Secretary), acknowledging the applicant's commitment to submit to the Secretary, an annual credit assessment of the applicant by a rating agency, an annual review and certification of the security of the Government guarantee that is audited by an independent certified public accounting firm or Federal banking regulator, annual consolidated financial statements audited by an independent certified public accountant each year during which the guaranteed bonds are outstanding, and other such information requested by the Secretary.

* * * * *

(c) The Secretary may condition the release of funds related to a guarantee bond on the guaranteed lender's provision of additional or supplemental information related to agency underwriting, regulatory compliance, program policy objectives, or collateral valuation.

■ 17. Revise § 1720.11 to read as follows:

§ 1720.11 Servicing.

The Secretary, or other agent of the Secretary on his or her behalf, shall have the right to service the guaranteed bond, and periodically inspect the facilities, assets, books, and accounts of the guaranteed lender or the collateral agent to ascertain compliance with the provisions of the RE Act and the bond documents.

■ 18. Amend § 1720.12 by revising paragraphs (a)(3) through (5) and (b) and adding paragraphs (c) through (e) to read as follows:

§ 1720.12 Reporting requirements.

(a) * * *

(3) Pro forma projection of the guaranteed lender's balance sheet, income statement, and statement of cash flows with detailed assumptions over the ensuing five years;

(4) Credit assessment issued by a rating agency, or such other evidence of creditworthiness as may be required by the Administrator under § 1720.5(b)(2);

(5) Credit rating, by a rating agency on its senior secured debt or its corporate credit rating, as applicable, without regard to the guarantee and satisfactory to the Secretary, or such other evidence of creditworthiness as may be required by the Administrator under § 1720.5(b)(2); and

* * * * *

(b) As long as any guaranteed bonds remain outstanding, the guaranteed lender will provide the Secretary with the following items each quarter within seven (7) business days of the guaranteed lender's quarter end:

(1) A list of pledged collateral which includes borrowers' billing information, and other information reasonably requested by RUS.

(2) A list of the guaranteed lender's criticized loans within 30 days of the end of each calendar quarter.

(c) The bond documents shall specify such bond monitoring, and financial and internal audit reporting requirements relating to the pledged collateral as deemed appropriate by the Secretary.

(d) Leveraging data must be submitted to RUS within five (5) business days after the guaranteed lender publishes its 10–K or 10–Q form or financial statements, as applicable.

(e) The use of the proceeds of the guaranteed bonds for the construction of new projects is subject to the environmental review requirements in accordance with 7 CFR part 1970. Prior to the guaranteed lender using the proceeds of the guaranteed bonds to make loans to borrowers for the construction of new projects, the guaranteed lender must provide sufficient details about the proposed construction to RUS so it can comply with the environmental requirements of 7 CFR part 1970. The guaranteed lender is prohibited from using the proceeds of guaranteed bonds to fund loans to borrowers for new construction projects without RUS's written acknowledgment that the environmental requirements of 7 CFR part 1970 have been met with respect to each such project.

PART 1785—LOAN ACCOUNT COMPUTATIONS, PROCEDURES AND POLICIES FOR ELECTRIC AND TELEPHONE BORROWERS

■ 19. The authority citation for part 1785 continues to read as follows:

Authority: 7 U.S.C. 901 *et seq.;* Title I, Subtitle D, sec. 1403, Omnibus Budget Reconciliation Act of 1987, Pub. L. 100–203; Pub. L. 103–354, 108 Stat. 3178 (7 U.S.C. 6941 *et seq.*).

■ 20. Revise § 1785.66 to read as follows:

§ 1785.66 General.

This subpart sets forth policies and procedures on the Rural Utilities Service (RUS) cushion of credit payments program. The cushion of credit payments program will be maintained only for accounts in existence on December 20, 2018. Once an account has been closed, it may not be reopened. Deposits in the borrower's cushion of credit account may only be used as described in this subpart and applicable law.

■ 21. Revise § 1785.68 to read as follows:

§ 1785.68 RUS cushion of credit payment accounts.

Effective December 20, 2018, no new cushion of credit accounts may be established. Deposits remaining in the cushion of credit accounts will bear an interest rate equal to the one-year Treasury interest rate in effect on October 1st for each year thereafter.

■ 22. Revise § 1785.69 to read as follows:

§ 1785.69 Cushion of credit payment account computations.

(a) *Deposits.* Cushion of credit deposits are credited to the borrowers' cushion of credit accounts as of December 20, 2018, with no further deposits accepted after that date.

(b) *Interest.* Interest at the rate provided for in § 1785.68 will be credited on a quarterly basis to cushion of credit accounts. Interest earned will appear as a reduction in the interest billed on the borrower's RUS notes and will be separately shown on RUS Form 694, ''Statement of Interest and Principal Due.''

■ 23. Revise § 1785.70 to read as follows:

§ 1785.70 Application of Rural Electric and Telephone Revolving Fund (RETRF) cushion of credit payments.

(a) If a maturing installment on an RUS note or a note which has been guaranteed by RUS is not received by its due date, funds will be withdrawn from the borrower's cushion of credit account and applied as of the installment due date beginning with the oldest of such notes as follows: first, to current interest then due on all notes; second, to the accumulated interest due, if any, on all notes; and third, to the principal then due on all notes.

(b) A borrower may reduce the balance of its cushion of credit account only if the amount obtained from the reduction is used to make scheduled payments on loans made or guaranteed under the Act.

(c) The Administrator of RUS may, consistent with law, authorize the requested release of cushion of credit deposits to a borrower when the cushion of credit balance will exceed the total value of the borrower's outstanding loans made or guaranteed by RUS.

(d) Once the balance in an individual cushion of credit account reaches zero, that cushion of credit account shall be closed. Once balances in all cushion of credit accounts reach zero, the cushion of credit program will be terminated.

(e) As the Rural Utilities Service phases out the cushion of credit program, the Agency may from time to time publish announcements in the **Federal Register**, or on its website related to the efficient administration of the cushion of credit program.

Andrew Berke,

Administrator, Rural Utilities Service.

[FR Doc. 2022–25788 Filed 12–5–22; 8:45 am]

BILLING CODE 3410–15–P

DEPARTMENT OF AGRICULTURE

Rural Housing Service

7 CFR Part 3560

[Docket No. RHS–22–MFH–0024]

Temporary Change in the Tenant Recertification Requirements

AGENCY: Rural Housing Service, USDA.

ACTION: Notice.

SUMMARY: The Rural Housing Service (RHS or the Agency), a Rural Development (RD) agency of the United States Department of Agriculture (USDA), is announcing a temporary exception to the tenant recertification requirements for the Section 515 Rural Rental Housing (RRH) Program and Section 514 Off-Farm Labor Housing (FLH) Program.

DATES: The temporary exception to the tenant recertification requirements will be effective on January 1, 2023, and expire on December 31, 2023.

FOR FURTHER INFORMATION CONTACT: Michael Resnik, Acting Director, Multi-Family Housing Asset Management Division, RHS, U.S. Department of Agriculture via email: *michael.resnik@usda.gov,* or by phone 202–430–3114.

SUPPLEMENTARY INFORMATION:

Authority

Section 515 Rural Rental Housing Direct Loans Program (42 U.S.C. 1485—Authorized under the Housing Act of 1949 (Pub. L. 81–171), and Public Law 102–550. Section 514 Farm Labor Housing Direct Loans and Grants Program (42 U.S.C. 1484)—Authorized under Title V of the Housing Act of 1949 (Pub. L. 81–171).

Background

The RHS is committed to helping improve the economy and quality of life in rural areas by offering a variety of programs. The Agency offers loans, grants, and loan guarantees to help create jobs, expand economic development, and provide critical infrastructure investments. RHS also provides technical assistance loans and grants by partnering with agricultural producers, cooperatives, Indian tribes, non-profits, and other local, state, and Federal agencies. Multifamily Housing (MFH) assists rural property owners through loans, loan guarantees, and grants that enable owners to develop and rehabilitate properties for low-income, elderly, and disabled individuals and families as well as domestic farm laborers.

Section 514 direct loans are provided to eligible borrowers for the development of on-farm or off-farm housing for farm laborers. Loans may be used to buy, build, improve, or repair housing (including furnishings and related facilities) for farm laborers. The Section 515 multifamily housing program offers direct loans for the development of new, or rehabilitation of existing, rental housing for low-income individuals and families in rural areas.

On October 13, 2022, the Social Security Administration announced an 8.7% increase in Social Security and Supplemental Security Income (SSI) benefits in 2023. According to the Social Security Administration, Social Security benefits will increase by an average of more than $140 per month starting in January 2023. This increase is due in part to the current inflationary pressures on the economy and a demanding labor market that has dramatically increased salaries, also seen in HUD's average increase of 11–12% in Area Median Income this year.

The regulation at 7 CFR 3560.152(e) requires, among other things, that tenant households must be recertified and must execute a tenant certification form at least annually or whenever a change in household income of $100 or more per month occurs.

The 8.7% cost-of-living adjustment (COLA) will begin with benefits payable in January 2023. As this would require recertifications for most Social Security recipients, the Agency is temporarily waiving the recertification requirement for tenants whose household income, regardless of income type, has increased by $100 or more, but less than $200. Accordingly, during the exception period, tenants will not be required to execute a tenant certification form unless their household income changes by $200 or more per month. This temporary change also aligns the MFH program with the current Housing and Urban Development (HUD) regulatory requirement. This is a temporary waiver that will be in place through calendar year 2023, expiring on December 31, 2023.

Temporary Change in Tenant Recertification Requirements

Pursuant to 7 CFR 3560.8, the RHS Administrator may make an exception to any provision of part 3560 or address any omissions provided that the exception is consistent with the applicable statute, does not adversely affect the interest of the Federal Government, and does not adversely affect the accomplishment of the purposes of the MFH programs or application of the requirement would result in undue hardship on the tenants. To alleviate the burden of unnecessary work for management agents and tenants, the following guidance is being provided for interim tenant certifications:

The Agency is temporarily waiving the recertification requirement for tenants whose household income has changed by $100 or more, but less than $200 per month. During the period of the waiver, tenant households must be recertified and must execute a tenant certification form at least annually or whenever a change in household income of $200 or more per month occurs.

This temporary exception is effective January 1, 2023, and will expire on December 31, 2023.

The requirement that borrower must recertify for changes of $50 per month, if the tenant requests that such a change be made, is still in effect.

This exception does not apply to, or change the requirements for, annual renewal certifications.

Agency Field staff will be advised to provide a copy of this notice to all borrowers and management agents. Through the provided notification, borrowers and management agents will be instructed to provide a written copy of the notice to all tenants immediately, including posting the notice at each property.

Paperwork Reduction Act

The temporary exception to tenant recertification requirements contains no new reporting or recordkeeping burdens under OMB control number 0575–0189 that would require approval under the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35).

Non-Discrimination Statement

In accordance with Federal civil rights laws and USDA civil rights regulations and policies, the USDA, its Mission Areas, agencies, staff offices, employees, and institutions participating in or administering USDA programs are prohibited from discriminating based on race, color, national origin, religion, sex, gender identity (including gender expression), sexual orientation, disability, age, marital status, family/parental status, income derived from a public assistance program, political beliefs, or reprisal or retaliation for prior civil rights activity, in any program or activity conducted or funded by USDA (not all bases apply to all programs). Remedies and complaint filing deadlines vary by program or incident.

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, audiotape, 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 Federal Relay Service at (800) 877–8339.

To file a program discrimination complaint, a complainant should complete a Form AD–3027, *USDA Program Discrimination Complaint Form,* which can be obtained online at *https://www.ascr.usda.gov/complaint_filing_cust.html,* from any USDA office, by calling (866) 632–9992, or by writing 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 an 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, Washington, DC 20250–9410; or (2) Fax: (833) 256–1665 or (202) 690–7442; or (3) Email: *Program.Intake@usda.gov.*

Jamal Habibi,

Acting Administrator, Rural Housing Service.

[FR Doc. 2022–26434 Filed 12–5–22; 8:45 am]

BILLING CODE 3410–XV–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 25

[Docket No. FAA–2021–0891; Special Condition No. 25–825–SC]

Special Conditions: Airbus Model A321neoXLR Airplane; Passenger Protection From External Fire

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final special conditions.

SUMMARY: These special conditions are issued for the Airbus Model A321neoXLR airplane. This airplane will have a novel or unusual design feature when compared to the technology envisaged by the airworthiness standards for transport category airplanes. This design feature is an integral rear center tank (RCT). The applicable airworthiness regulations do not contain adequate or appropriate safety standards for this design feature. These special conditions contain the additional safety standards that the Administrator considers necessary to establish a level of safety equivalent to that established by the existing airworthiness standards.

DATES: Effective January 5, 2023.

FOR FURTHER INFORMATION CONTACT: Shannon Lennon, Human Machine Interface, AIR–626, Technical Innovation Policy Branch, Policy and Innovation Division, Aircraft Certification Service, Federal Aviation Administration, 2200 South 216th Street, Des Moines, Washington 98198; telephone and fax 206–231–3209; email *shannon.lennon@faa.gov.*

SUPPLEMENTARY INFORMATION:

Background

On September 16, 2019, Airbus applied for an amendment to Type Certificate No. A28NM to include the new Model A321neoXLR airplane. The Model A321neoXLR airplane, which is a derivative of the Model A321neoACF airplane currently approved under Type

Certificate No. A28NM, is a twin-engine transport category aircraft that seats 244 passengers and has a maximum takeoff weight of 202,000 lbs.

Type Certification Basis

Under the provisions of title 14, Code of Federal Regulations (14 CFR) 21.101, Airbus must show that the Model A321neoXLR airplane meets the applicable provisions of the regulations listed in Type Certificate No. A28NM, or the applicable regulations in effect on the date of application for the change, except for earlier amendments as agreed upon by the FAA.

If the Administrator finds that the applicable airworthiness regulations (*e.g.,* 14 CFR part 25) do not contain adequate or appropriate safety standards for the Airbus Model A321neoXLR airplane because of a novel or unusual design feature, special conditions are prescribed under the provisions of § 21.16.

Special conditions are initially applicable to the model for which they are issued. Should the type certificate for that model be amended later to include any other model that incorporates the same novel or unusual design feature, or should any other model already included on the same type certificate be modified to incorporate the same novel or unusual design feature, these special conditions would also apply to the other model under § 21.101.

In addition to the applicable airworthiness regulations and special conditions, the Airbus Model A321neoXLR airplane must comply with the fuel vent and exhaust emission requirements of 14 CFR part 34 and the noise certification requirements of 14 CFR part 36.

The FAA issues special conditions, as defined in 14 CFR 11.19, in accordance with § 11.38, and they become part of the type certification basis under § 21.101.

Novel or Unusual Design Feature

The Airbus Model A321neoXLR airplane will incorporate the following novel or unusual design feature:

An integral RCT.

Discussion

The Airbus Model A321neoXLR incorporates an integral RCT. This tank is a ''center'' fuel tank, in that it is located in the airplane fuselage rather than in its wings. The tank is a ''rear'' tank, in that it is located aft of the wheel bay; it will be in an area of the lower fuselage that partially replaces the aft cargo compartment of the airplane from which this model is derived. The top of the tank will be directly below the floor of the passenger cabin. The fuel tank will be ''integral'' to the airplane, in that its walls will be part of the airplane structure. The exterior skin of the airplane fuselage will constitute part of the walls of the fuel tank, and these areas will lack the thermal/acoustic insulation that usually lines the exterior skin of an airplane fuselage.

This design was not envisaged by the FAA's regulatory requirements for insulation installations on transport category airplanes. 14 CFR 25.856(b) requires all thermal/acoustic insulation in the lower half of the airplane fuselage and their installation to comply with the flame penetration resistance test of appendix F, part VII. The FAA adopted § 25.856(b) to raise the level of post-crash fire safety on transport category airplanes. Part VII of appendix F to part 25 requires a stringent test method for all thermal/acoustic insulation proposed for installation in the lower half of the fuselage. The FAA's intent in imposing this requirement was to ensure that this insulation provides an additional barrier between the occupants and an external post-crash fire, especially a fire resulting from a pool of spilled aviation fuel.[1] This barrier extends the time available for evacuation.

While the rule applies to the thermal/acoustic insulation that an applicant proposes as part of their design, it does not require applicants to install such insulation. Since the fuselage skins of the lower half of transport category airplanes are generally insulated, and were at the time these standards were developed, the FAA considered this approach to be sufficient to ensure safety. The rule also noted, however, that if applicants began to propose designs that omitted this thermal/acoustic insulation, the FAA would revisit the need for a specific fuselage burnthrough standard.[2]

Thus, since this design will lack thermal/acoustic insulation under the fuselage skin in the area of the fuel tank, current FAA regulations do not ensure that it will provide a continuous flame penetration (burnthrough) resistant barrier between the passengers and an external fire, nor that it will provide enough protection, against an external post-crash fire, to allow time for passengers to evacuate.

According to Airbus, its design does not allow for compliant thermal/acoustic insulation to be placed beneath the cabin floor. This large volume of unheated liquid (fuel), directly below the floor of the passenger cabin, would, without mitigation, create a 'cold feet' effect for the passengers above it. Therefore, Airbus will install insulation panels between the fuel tank and the cabin floor, for comfort reasons. These insulation panels would normally be required to meet § 25.856(b). However, Airbus states that it is technically not feasible to install thermal/acoustic insulation that complies with § 25.856(b), due to the lack of space in this area and the need to keep nearby decompression panels free of blockages and ensure adequate ventilation.

Special conditions are needed to address the assumption in the FAA's current flammability standards that proposed airplane designs would include thermal/acoustic insulation in the lower fuselage, and to ensure that this proposed design does not reduce the time available for passenger evacuation in the case of a post-crash external fire. Specifically, the FAA will require that the lower half of the airplane fuselage, spanning the longitudinal area of the tank, be resistant to fire penetration. ''Resistant to fire penetration'' will, for this special condition, mean that this area provides fire penetration resistance equivalent to the resistance which would be provided if the fuselage were lined with thermal/acoustic insulation that meets the flame penetration resistance test requirements of part VII of appendix F of part 25. The applicant's method of compliance may, but is not required to, be based upon any inherent flame penetration resistance capability provided by the construction of the fuel tank and/or other surrounding features.

These special conditions contain the additional safety standards that the Administrator considers necessary to establish a level of safety equivalent to that established by the existing airworthiness standards.

Discussion of Comments

The FAA issued Notice of Proposed Special Conditions No. 25–21–04–SC for the Model A321neoXLR airplane, which was published in the **Federal Register** on April 6, 2022 (87 FR 19811). The FAA received four comments from the Boeing Company (Boeing).

Comment Summary: Boeing requested that the discussion section of these special conditions describe the RCT as an ''auxiliary,'' rather than ''center,'' fuel tank because the airplane also has a ''center'' wing (main) tank, and because, as described by Advisory Circular (AC) 25–8, *Auxiliary Fuel*

[1] See pg. 2 of FAA Advisory Circular 25.856–2A, *Installation of Thermal/Acoustic Insulation for Burnthrough Protection.*

[2] *Improved Flammability Standards for Thermal/Acoustic Insulation Materials Used In Transport Category Airplanes,* 68 FR 45046, 45049 (Jul. 31, 2003).

Systems Installations, the RCT would be connected to the main tank with a fuel feed line. Boeing also requested that the discussion section describe the tank as an ''aft'' fuel tank rather than a ''rear'' tank, because it will be aft of the wheel bay.

FAA Response: No change to the terms used to describe the RCT in these special conditions is necessary. The existing terms are accurate, consistent with the applicant's nomenclature, and adequate for their purpose.

Comment Summary: Boeing requested that the discussion section of these special conditions acknowledge that AC 25.856–2A [3] provides guidance for center wing tank designs. Boeing further requested that the discussion, according to guidance provided in that AC for the wing box area, also indicate that insulation panels installed above a fuel tank are not required to meet § 25.856(b).

FAA Response: The discussion for these special conditions acknowledges that § 25.856(b) does not adequately address designs like the RCT of the A321neoXLR. This aircraft presents a novel fuselage design that does not incorporate thermal/acoustic insulation in areas where the RCT is integral to the fuselage, nor does it include thermal/acoustic insulation above the RCT that will meet § 25.856(b). This design presents a fire penetration resistance (burnthrough) vulnerability that is addressed by these special conditions. The same vulnerability does not exist with transport airplane wing box construction due to that structure's significant mass, and large surface area that dissipates heat. Therefore, adding insulation over the wingbox, would not contribute to its fire penetration resistance. 14 CFR 25.856(b) excepts the installation of insulation in locations where it would not contribute to fire penetration resistance. However, the wing box example in AC 25.856–2A only addresses the FAA's assessment of the wing box area in consideration of thermal/acoustic insulation installations that would not contribute to fire penetration resistance. It does not suggest that all center fuel tanks do not necessitate the installation of thermal/acoustic insulation that meets § 25.856(b). For this reason, the FAA declines to change the discussion section of these special conditions.

Comment Summary: Boeing requested that the special conditions require the RCT fire penetration resistance capability to either be equivalent to the capability provided by the wing box area or meet the requirements of 14 CFR 25.963(e)(2). Boeing's rationale was that the FAA's proposed standard of fire penetration resistance equivalent to that of a fuselage lined with thermal/acoustic insulation that meets the flame penetration resistance test requirements of part VII of appendix F, does not address hazards associated with fuel tanks and is not applicable to the wing box area.

FAA Response: These special conditions are intended to ensure that the existing RCT area fuselage design establishes the same level of safety as would 14 CFR 25.856(b). When thermal/acoustic insulation is installed, either along the fuselage skin or under the passenger cabin floor, it should be fire penetration resistant and delay the onset of fire into the passenger cabin. These special conditions are not intended to ensure the RCT is constructed to provide a fire penetration resistance capability that is similar to that of the wing box area. It is also unnecessary to require that the RCT meet rules such as 14 CFR 25.963(e)(2), which provides standards for fuel tank access covers.

The special conditions are adopted as proposed.

Applicability

As discussed above, these special conditions are applicable to the Airbus Model A321neoXLR airplane. Should Airbus apply at a later date for a change to the type certificate to include another model incorporating the same novel or unusual design feature, these special conditions would apply to that model as well.

Conclusion

This action affects only a certain novel or unusual design feature on one model of airplane. It is not a rule of general applicability.

List of Subjects in 14 CFR Part 25

Aircraft, Aviation safety, Reporting and recordkeeping requirements.

Authority Citation

The authority citation for these special conditions is as follows:

Authority: 49 U.S.C. 106(f), 106(g), 40113, 44701, 44702, 44704.

The Special Conditions

Accordingly, pursuant to the authority delegated to me by the Administrator, the following special conditions are issued as part of the type certification basis for Airbus Model A321neoXLR airplanes.

Passenger Protection From External Fire

The lower half of the fuselage, spanning the longitudinal location of the rear center fuel tank, must be resistant to fire penetration.

Issued in Kansas City, Missouri, on November 30, 2022.

Patrick R. Mullen,

Manager, Technical Innovation Policy Branch, Policy and Innovation Division, Aircraft Certification Service.

[FR Doc. 2022–26435 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

[3] See pg. 2 of FAA Advisory Circular 25.856–2A, *Installation of Thermal/Acoustic Insulation for Burnthrough Protection.*

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2022–1472; Airspace Docket No. 22–AWA–8]

RIN 2120–AA66

Amendment of Class C Airspace; Manchester, NH

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action amends the Manchester, NH Class C airspace description to update the Manchester Airport name and airport reference point (ARP) geographic coordinates to match the FAA's National Airspace System Resources (NASR) database information. This action also updates the Nashua Airport name. Additionally, references to the Manchester, NH (MHT), VHF Omnidirectional Range/Distance Measuring Equipment (VOR/DME) and Boire Field Airport and their geographical coordinates are added to the Class C description header. This action does not change the boundaries, altitudes, or operating requirements of the Class C airspace area.

DATES: Effective date 0901 UTC, February 23, 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 7400.11 and publication of conforming amendments.

ADDRESSES: FAA Order 7400.11G, Airspace Designations and Reporting Points, and subsequent amendments can be viewed online at *www.faa.gov/air_traffic/publications/.* For further information, you can contact the Rules and Regulations Group, Federal Aviation Administration, 800 Independence Avenue SW, Washington, DC 20591; telephone: (202) 267–8783.

FOR FURTHER INFORMATION CONTACT: Paul Gallant, 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 updates the information in the Manchester, NH Class C airspace description.

History

During a recent review of the Manchester, NH Class C airspace description, the FAA identified the need to update the name and ARP geographic coordinates for the Manchester Airport, and to update the name of the Nashua Airport, NH. This action also makes administrative edits to the airspace description header to add the geographic coordinates for the Boire Field Airport and the Manchester, NH (MHT), VOR/DME, because these facilities are used in the Class C description. There are no changes to the boundaries, altitudes, or air traffic control services resulting from this action.

Class C airspace areas are published in paragraph 4000 of FAA Order 7400.11G, dated August 19, 2022, and effective September 15, 2022, which is incorporated by reference in 14 CFR 71.1. The Class C airspace listed in this document will be published subsequently in FAA Order JO 7400.11.

Availability and Summary of Documents for Incorporation by Reference

This document amends FAA Order 7400.11G, Airspace Designations and Reporting Points, dated August 19, 2022, and effective September 15, 2022. FAA Order 7400.11G is publicly available as listed in the **ADDRESSES** section of this document. FAA Order 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 the Manchester, NH Class C airspace description as published in FAA Order 7400.11G, Airspace Designations and Reporting Points. The ''Manchester Airport'' name is changed to ''Manchester Boston Regional Airport'', to match the Airport Master Record database, and the ARP geographic coordinates are updated from ''lat. 42°56′00″ N, long. 71°26′16″ W'' to ''lat. 42°55′58″ N, long. 71°45′39″ W.'' The ARP geographic coordinates update is made to match the FAA's National Airspace System Resource database information. The ''Nashua Airport'' name in the Class description is updated to ''Boire Field Airport'' to match the Airport Master Records database. Additionally, administrative edits are made to the Class C airspace description header by adding the Boire Field Airport and the Manchester VOR/DME and their geographical coordinates, which are used in the airspace description.

This action consists of administrative changes only and does not affect the boundaries, altitudes, or operating requirements of the airspace. Therefore, notice and public procedure under 5 U.S.C. 553(b) is unnecessary.

FAA Order 7400.11, Airspace Designations and Reporting Points, is published yearly and effective on September 15.

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 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 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 making administrative edits to the Manchester, NH, Class C airspace description 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). 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. Accordingly, 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, effective September 15, 2022, is amended as follows:

Paragraph 4000 Class C Airspace.

* * * * *

ANE NH C Manchester, NH [Amended]

Manchester Boston Regional Airport, NH
(Lat. 42°55′58″ N, long. 71°45′39″ W)
Boire Field Airport, Nashua, NH
(Lat. 42°46′57″ N, long. 71°30′51″ W)
Manchester, NH VOR/DME
(Lat. 42°52′07″ N, long. 71°22′10″ W)

That airspace extending upward from the surface to and including 4,300 feet MSL within a 5-mile radius of the Manchester Boston Regional Airport; including that airspace extending upward from 2,500 feet MSL to and including 4,300 feet MSL within a 10-mile radius of the airport; including that airspace from 1,500 feet MSL between a 5-mile radius and 10-mile radius south of the airport from Interstate 93 clockwise to the eastern edge of the 5-mile radius of Boire Field Airport; including that airspace from 2,000 feet MSL between a 5-mile radius and 10-mile radius north of the airport from the Manchester, NH VOR/DME 315° radial clockwise to Interstate 93.

Issued in Washington, DC, on November 30, 2022.

Scott M. Rosenbloom,

Manager, Airspace Rules and Regulations.

[FR Doc. 2022–26458 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2022–0186; Airspace Docket No. 22–AAL–6]

RIN 2120–AA66

Revocation of Colored Federal Airways Blue 7 (B–7) and Green 9 (G–9); Bethel, AK

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action revokes Colored Federal airways Blue 7 (B–7) and Green 9 (G–9) in the vicinity of Bethel, AK, due to the planned decommissioning of the Oscarville, AK (OSE), Non-Directional Beacon (NDB).

DATES: Effective date 0901 UTC, February 23, 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: FAA Order JO 7400.11G, Airspace Designations and Reporting Points, and subsequent amendments can be viewed online at *www.faa.gov/air_traffic/publications/.* For further information, you can contact the Rules and Regulations Group, 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 modifies the route structure as necessary to preserve the safe and efficient flow of air traffic within the National Airspace System (NAS).

History

The FAA published a notice of proposed rulemaking (NPRM) for Docket No. FAA–2022–0186 in the **Federal Register** (87 FR 13663; March 10, 2022), revoking Colored Federal airways B–7 and G–9 in the vicinity of Bethel, AK, due to the planned decommissioning of the Oscarville, AK, NDB. Interested parties were invited to participate in this rulemaking effort by submitting comments on the proposal. No comments were received.

Green Federal airways are published in paragraph 6009(a) and Blue Federal airways are published in paragraph 6009(d) of FAA Order JO 7400.11G, dated August 19, 2022, and effective September 15, 2022, which is incorporated by reference in 14 CFR 71.1. The Colored Federal airways listed in this document will be published subsequently in FAA Order JO 7400.11.

Availability and Summary of Documents for Incorporation by Reference

This document amends FAA Order JO 7400.11G, Airspace Designations and Reporting Points, 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. 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 revoking Colored Federal airways B–7 and G–9 in the vicinity of Bethel, AK, due to the decommissioning of the Oscarville, AK, NDB. The amendments are described below.

B–7: B–7 extends between the Cape Newenham, AK, NDB and the Oscarville, AK, NDB. The airway is removed in its entirety.

G–9: G–9 extends between the Oscarville, AK, NDB and the Cairn Mountain, AK, NDB. The airway is removed in its entirety.

FAA Order JO 7400.11, Airspace Designations and Reporting Points, is published yearly and effective on September 15.

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 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 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

The FAA has determined that this airspace action of revoking Colored Federal airway B–7 and G–9, due to the planned decommissioning of the Oscarville, AK, NDB, 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), and paragraph 5–6.5k, which categorically excludes from further environmental review the publication of existing air traffic control procedures that do not essentially change existing tracks, create new tracks, change altitude, or change concentration of aircraft on these tracks. 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. Accordingly, 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 6009(a) Green Federal Airways.

* * * * *

G–9 [Removed]

* * * * *

Paragraph 6009(d) Blue Federal Airways.

* * * * *

B–7 [Removed]

* * * * *

Issued in Washington, DC, on November 30, 2022.

Scott M. Rosenbloom,

Manager, Airspace Rules and Regulations.

[FR Doc. 2022–26379 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2022–0765; Airspace Docket No. 22–AAL–22]

RIN 2120–AA66

Revocation of Colored Federal Airway Red-1 (R–1) Vicinity of King Salmon, AK

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action revokes the Colored Federal airway Red 1 (R–1) in the vicinity of King Salmon, AK, due to the airway no longer being used by pilots as the overlaying United States Area Navigation (RNAV) route T–230 provides better navigation capability with a lower minimum enroute altitude (MEA).

DATES: Effective date 0901 UTC, February 23, 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: FAA Order JO 7400.11G, Airspace Designations and Reporting Points, and subsequent amendments can be viewed online at *www.faa.gov/air_traffic/publications/.* For further information, you can contact the Rules and Regulations Group, 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 modifies the route structure as necessary to preserve the safe and efficient flow of air traffic within the National Airspace System (NAS).

History

The FAA published a notice of proposed rulemaking (NPRM) for Docket No. FAA–2022–0765 in the **Federal Register** (87 FR 35692; June 13, 2022), revoking Colored Federal airway R–1 due to the airway no longer being used by pilots as the overlaying RNAV route T–230 provides better navigation with a lower MEA. Interested parties were invited to participate in this rulemaking effort by submitting comments on the proposal. No comments were received.

Red Federal airways are published in paragraph 6009(b) of FAA Order JO 7400.11G, dated August 19, 2022, and effective September 15, 2022, which is incorporated by reference in 14 CFR 71.1. The Colored Federal airway listed in this document will be published subsequently in FAA Order JO 7400.11.

Differences From the NPRM

Subsequent to the NPRM, the FAA identified an inadvertent typographical error that listed the R–1 removal under FAA Order JO 7400.11G, paragraph 6009(a) in error in the regulatory text. The correct FAA Order JO 7400.11G paragraph is paragraph 6009(b). This action corrects the FAA Order JO 7400.11G paragraph reference typographical error in the regulatory text to reflect it as paragraph 6009(b) Red Federal airways.

The rulemaking action to revoke R–1 is unaffected by this administrative error correction.

Availability and Summary of Documents for Incorporation by Reference

This document amends FAA Order JO 7400.11G, Airspace Designations and Reporting Points, 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. 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 revoking Colored Federal airway R–1, due to the airway no longer being used by pilots as the overlaying RNAV route T–230 provides better navigation with a lower MEA. The amendment is described below.

R–1: R–1 extends between the St Paul Island, AK, NDB/DME and the Chinook, AK, NDB. The airway is removed in its entirety.

FAA Order JO 7400.11, Airspace Designations and Reporting Points, is published yearly and effective on September 15.

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 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 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

The FAA has determined that this airspace action of revoking Colored Federal airway R–1, due to the airway no longer being used by pilots and the overlaying RNAV route T–230 providing better navigation with a lower MEA, 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), and paragraph 5–6.5k, which categorically excludes from further environmental review the publication of existing air traffic control procedures that do not essentially change existing tracks, create new tracks, change altitude, or change concentration of aircraft on these tracks. 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. Accordingly, 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 6009(b) Red Federal Airways.

R–1 [Removed]

* * * * *

Issued in Washington, DC, on November 30, 2022.

Scott M. Rosenbloom,

Manager, Airspace Rules and Regulations.

[FR Doc. 2022–26382 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2022–0109; Airspace Docket No. 22–AAL–10]

RIN 2120–AA66

Proposed Revocation of Colored Federal Airway Blue 79 (B–79); Annette Island, AK

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action revokes Colored Federal airway Blue 79 (B–79) in the vicinity of Annette Island, AK, due to the planned decommissioning of the Nichols, AK (ICK), Non-Directional Beacon (NDB).

DATES: Effective date 0901 UTC, February 23, 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: FAA Order JO 7400.11G, Airspace Designations and Reporting Points, and subsequent amendments can be viewed online at *www.faa.gov/air_traffic/publications/.* For further information, you can contact the Rules and Regulations Group, 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 modifies the route structure as necessary to preserve the safe and efficient flow of air traffic within the National Airspace System (NAS).

History

The FAA published a notice of proposed rulemaking (NPRM) for Docket No. FAA–2022–0109 in the **Federal Register** (87 FR 10992; February 28, 2022), revoking Colored Federal airway B–79 in the vicinity of Annette Island, AK, due to the planned decommissioning of the Nichols, AK, NDB. Interested parties were invited to participate in this rulemaking effort by submitting comments on the proposal. No comments were received.

Blue Federal airways are published in paragraph 6009(d) of FAA Order JO 7400.11G, dated August 19, 2022, and effective September 15, 2022, which is incorporated by reference in 14 CFR 71.1. The Colored Federal airway listed in this document will be published subsequently in FAA Order JO 7400.11.

Availability and Summary of Documents for Incorporation by Reference

This document amends FAA Order JO 7400.11G, Airspace Designations and Reporting Points, 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. 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 revoking Colored Federal airway B–79 due to the planned decommissioning of the Nichols, AK, NDB. The amendment is described below.

B–79: B–79 extends between the Sandspit, BC, Canada, NDB and the Nichols, AK, NDB, excluding the airspace within Canada. The airway is removed in its entirety.

FAA Order JO 7400.11, Airspace Designations and Reporting Points, is published yearly and effective on September 15.

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 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 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

The FAA has determined that this airspace action of revoking Colored Federal airway B–79, due to the planned decommissioning of the Nichols, AK, NDB, 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), and paragraph 5–6.5k, which categorically excludes from further environmental review the publication of existing air traffic control procedures that do not essentially change existing tracks, create new tracks, change altitude, or change concentration of aircraft on these tracks. 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. Accordingly, 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 6009(d) Blue Federal Airways.

* * * * *

B–79 [Removed]

* * * * *

Issued in Washington, DC, on November 30, 2022.

Scott M. Rosenbloom,

Manager, Airspace Rules and Regulations.

[FR Doc. 2022–26378 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2022–0299; Airspace Docket No. 22–AAL–18]

RIN 2120–AA66

Revocation of Colored Federal Airway Amber 6 (A–6); St. Mary's, AK

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action revokes Colored Federal airway Amber 6 (A–6) due to the planned decommissioning of the St Marys, AK (SMA), Non-Directional Beacon (NDB) in the vicinity of St. Mary's, AK.

DATES: Effective date 0901 UTC, February 23, 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: FAA Order JO 7400.11G, Airspace Designations and Reporting Points, and subsequent amendments can be viewed online at *www.faa.gov/air_traffic/publications/*. For further information, you can contact the Rules and Regulations Group, 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 modifies the route structure as necessary to preserve the safe and efficient flow of air traffic within the National Airspace System (NAS).

History

The FAA published a notice of proposed rulemaking (NPRM) for Docket No. FAA–2022–0299 in the **Federal Register** (87 FR 19410; April 4, 2022), revoking Colored Federal airway A–6 due to the planned decommissioning of the St Marys, AK, NDB. Interested parties were invited to participate in this rulemaking effort by submitting comments on the proposal. No comments were received.

Amber Federal airways are published in paragraph 6009(c) of FAA Order JO 7400.11G, dated August 19, 2022, and effective September 15, 2022, which is incorporated by reference in 14 CFR 71.1. The Colored Federal airway listed in this document will be published subsequently in FAA Order JO 7400.11.

Availability and Summary of Documents for Incorporation by Reference

This document amends FAA Order JO 7400.11G, Airspace Designations and Reporting Points, 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. 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 revoking Colored Federal airway A–6 due to the planned decommissioning of the St Marys, AK, NDB in the vicinity of St. Mary's, AK. The amendment is described below.

A–6: A–6 extends between the St Marys, AK, NDB and the North River, AK, NDB. The airway is removed in its entirety.

FAA Order JO 7400.11, Airspace Designations and Reporting Points, is published yearly and effective on September 15.

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 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 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

The FAA has determined that this airspace action of revoking Colored Federal airway A–6, due to the planned decommissioning of the St Marys, AK, NDB, 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), and paragraph 5–6.5k, which categorically excludes from further environmental review the publication of existing air traffic control procedures that do not essentially change existing tracks, create new tracks, change altitude, or change concentration of aircraft on these tracks. 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. Accordingly, 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 6009(c) Amber Federal Airways.

* * * * *

A–6 [Removed]

* * * * *

Issued in Washington, DC, on November 30, 2022.

Scott M. Rosenbloom,

Manager, Airspace Rules and Regulations.

[FR Doc. 2022–26398 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2022–0617; Airspace Docket No. 22–ASW–4]

RIN 2120–AA66

Amendment of VOR Federal Airway V–573 and Area Navigation (RNAV) Route T–398 in the Vicinity of Sulphur Springs, TX

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action amends VHF Omnidirectional Range (VOR) Federal airway V–573 and Area Navigation (RNAV) route T–398. The FAA is taking this action due to the planned decommissioning of the VOR portion of the Sulphur Springs, TX (SLR), VOR/ Distance Measuring Equipment (VOR/ DME) navigational aid (NAVAID). The Sulphur Springs VOR is being decommissioned in support of the FAA's VOR Minimum Operational Network (MON) program.

DATES: Effective date 0901 UTC, February 23, 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: FAA Order JO 7400.11G, Airspace Designations and Reporting Points, and subsequent amendments can be viewed online at *www.faa.gov/air_traffic/publications/.* For further information, you can contact the Rules and Regulations Group, 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 modifies the route structure as necessary to preserve the safe and efficient flow of air traffic within the National Airspace System (NAS).

History

The FAA published a notice of proposed rulemaking for Docket No. FAA–2022–0617 in the **Federal Register** (87 FR 31436; May 24, 2022), amending VOR Federal airway V–573 and RNAV route T–398. The proposed amendment actions were due to the planned decommissioning of the VOR portion of the Sulphur Springs, TX, VOR/DME NAVAID. Interested parties were invited to participate in this rulemaking effort by submitting written comments on the proposal. No comments were received.

VOR Federal airways are published in paragraph 6010(a) and United States Area Navigation Routes are published in paragraph 6011 of FAA Order JO 7400.11G, dated August 19, 2022, and effective September 15, 2022, which is incorporated by reference in 14 CFR 71.1. The Air Traffic Service (ATS) routes listed in this document will be published subsequently in FAA Order JO 7400.11.

Availability and Summary of Documents for Incorporation by Reference

This document amends FAA Order JO 7400.11G, Airspace Designations and Reporting Points, 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. 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–573 and RNAV route T–398 due to the planned decommissioning of the VOR portion of the Sulphur Springs, TX (SLR), VOR/DME. The ATS route actions are described below.

V–573: V–573 extends between the Will Rogers, OK, VORTAC and the Little Rock, AR, VORTAC. The airway segment overlying the Sulphur Springs VOR/DME between the Bonham, TX, VORTAC and the Texarkana, AR, VORTAC is removed. As amended, the airway is changed to extend between the Will Rogers, OK, VORTAC and the Bonham, TX, VORTAC; and between the Texarkana, AR, VORTAC and the Little Rock, AR, VORTAC.

T–398: T–398 extends between the SLOTH, TX, waypoint (WP), and the GMINI, NC, WP. The route is extended further westward between the RRORY, TX, WP being established near the Bonham, TX, VORTAC and the SLOTH, TX, WP. The added RNAV route segment overlays the V–573 airway segment being removed between the Bonham, TX, VORTAC and the Texarkana, AR, VORTAC, noted above. The full route legal description is included in the amendments to part 71 set forth below.

The NAVAID radials listed in the VOR Federal airway description below are unchanged and stated in True degrees.

FAA Order JO 7400.11, Airspace Designations and Reporting Points, is published yearly and effective on September 15.

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 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 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

The FAA has determined that this action of amending VOR Federal airway V–573 and RNAV route T–398, due to the planned decommissioning of the VOR portion of the Sulphur Springs, TX, 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) and paragraph 5–6.5i, which categorically excludes from further environmental 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–573 [Amended]

From Will Rogers, OK; INT Will Rogers 195° and Ardmore, OK, 327° radials; Ardmore; to Bonham, TX. From Texarkana, AR; INT Texarkana 037° and Hot Springs, AR, 225° radials; Hot Springs; to Little Rock, AR.

* * * * *

Paragraph 6011 United States Area Navigation Routes.

* * * * *

T–398 RRORY, TX to GMINI, NC [Amended]

RRORY, TX	WP	(Lat. 33°32′14.95″ N, long. 096°14′03.45″ W)
MERIC, TX	WP	(Lat. 33°11′54.97″ N, long. 095°32′32.66″ W)
SLOTH, TX	WP	(Lat. 33°30′49.99″ N, long. 094°04′24.38″ W)
MUFRE, AR	FIX	(Lat. 34°05′31.32″ N, long. 093°10′43.80″ W)
LITTR, AR	WP	(Lat. 34°40′39.90″ N, long. 092°10′49.26″ W)
EMEEY, AR	WP	(Lat. 34°34′30.29″ N, long. 090°40′27.14″ W)
GOINS, MS	WP	(Lat. 34°46′12.64″ N, long. 089°29′46.81″ W)
HAGIE, AL	WP	(Lat. 34°42′25.87″ N, long. 087°29′29.76″ W)
FILUN, AL	WP	(Lat. 34°47′50.14″ N, long. 086°38′01.14″ W)
JILIS, GA	WP	(Lat. 34°57′23.98″ N, long. 085°08′03.46″ W)
CRAND, GA	FIX	(Lat. 34°57′28.88″ N, long. 084°51′20.59″ W)
BALNN, GA	WP	(Lat. 34°56′34.20″ N, long. 083°54′56.42″ W)
BURGG, SC	WP	(Lat. 35°02′00.55″ N, long. 081°55′36.86″ W)
GAFFE, SC	FIX	(Lat. 35°05′38.90″ N, long. 081°33′23.92″ W)
CRLNA, NC	WP	(Lat. 35°12′49.48″ N, long. 080°56′57.32″ W)
LOCAS, NC	FIX	(Lat. 35°12′05.18″ N, long. 080°26′44.89″ W)
RELPY, NC	FIX	(Lat. 35°12′45.70″ N, long. 079°47′28.76″ W)
GMINI, NC	WP	(Lat. 35°12′23.01″ N, long. 079°34′01.98″ W)

* * * * *

Issued in Washington, DC, on November 30, 2022.

Scott M. Rosenbloom,

Manager, Airspace Rules and Regulations.

[FR Doc. 2022–26397 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2022–0027; Airspace Docket No. 21–ANM–70]

RIN 2120–AA66

Amendment of Domestic VOR Federal Airway V–356; Mile High, CO

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action amends VHF Omnidirectional Range (VOR) Federal airway V–356 by revoking the airway segment between the FIDLE and ELORE Fixes. The FAA is taking this action due to the Mile High, CO, VOR/Tactical Air Navigation (VORTAC) signal coverage supporting the airway segment having been determined to be unusable below 18,000 feet mean sea level (MSL) during flight inspection.

DATES: Effective date 0901 UTC, February 23, 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: FAA Order JO 7400.11G, Airspace Designations and Reporting Points, and subsequent amendments can be viewed online at *www.faa.gov/air_traffic/publications/.* For further information, you can contact the Rules and Regulations Group, 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 modifies the 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 (NPRM) for Docket No. FAA–2022–0027 in the **Federal Register** (87 FR 4520; January 28, 2022), amending V–356 by revoking the airway segment between the FIDLE and ELORE Fixes due to the absence of a supporting navigational aid signal. Interested parties were invited to participate in this rulemaking effort by submitting comments on the proposal. No comments were received.

Domestic VOR Federal airways are published in paragraph 6010(a) of FAA Order JO 7400.11G, dated August 19, 2022, and effective September 15, 2022, which is incorporated by reference in 14 CFR 71.1. The VOR Federal airway listed in this document will be published subsequently in FAA Order JO 7400.11.

Availability and Summary of Documents for Incorporation by Reference

This document amends FAA Order JO 7400.11G, Airspace Designations and Reporting Points, 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. 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 revoking the V–356 airway segment between the FIDLE and ELORE Fixes due to the lack of usable navigational signal by the Mile High, CO, VORTAC below 18,000 feet MSL supporting the airway segment. FAA flight inspection determined the lack of navigational signal coverage during a routine inspection of V–356. The airway amendment is described below.

V–356: V–356 extends between the Red Table, CO, VOR/Distance Measuring Equipment (VOR/DME) and the Mile High, CO, VORTAC. As a result of the lack of Mile High VORTAC navigational signal coverage between the FIDLE and ELORE Fixes, the airway segment between the intersection of the Red Table VOR/DME 058° and the Kremmling, CO, VOR/DME 190° radials (FIDLE Fix) and the intersection of the Gill, CO, VOR/DME 211° and the Mile High VORTAC 265° radials (ELORE Fix) is removed. As amended, the airway is changed to extend between the Red Table, CO, VOR/DME and the FIDLE Fix and between the ELORE Fix and the Mile High, CO, VORTAC.

All NAVAID radials listed in the airway description below are unchanged and stated in True degrees.

FAA Order JO 7400.11, Airspace Designations and Reporting Points, is published yearly and effective on September 15.

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 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 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

The FAA has determined that this airspace action of amending V–356, due to the lack of navigational signal coverage below 18,000 feet MSL between the FIDLE and ELORE Fixes by the Mile High, CO, VORTAC, 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), and paragraph 5–6.5k, which categorically excludes from further environmental review the publication of existing air traffic control procedures that do not essentially change existing tracks, create new tracks, change altitude, or change concentration of aircraft on these tracks. 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. Accordingly, 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–356 [Amended]

From Red Table, CO; to INT Red Table 058° and Kremmling, CO, 190° radials. From INT Gill, CO, 211° and Mile High, CO, 265° radials; to Mile High.

* * * * *

Issued in Washington, DC, on November 30, 2022.

Scott M. Rosenbloom,

Manager, Airspace Rules and Regulations.

[FR Doc. 2022–26391 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2022–0162; Airspace Docket No. 22–AAL–12]

RIN 2120–AA66

Revocation of Colored Federal Airway Green 15 (G–15); St. Mary's, AK

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action revokes Colored Federal airway Green 15 (G–15) due to the planned decommissioning of the St Marys, AK (SMA), and Takotna River, AK (VTR), Non-Directional Beacons (NDBs).

DATES: Effective date 0901 UTC, February 23, 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: FAA Order JO 7400.11G, Airspace Designations and Reporting

Points, and subsequent amendments can be viewed online at *www.faa.gov/air_traffic/publications/.* For further information, you can contact the Rules and Regulations Group, 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 modifies the route structure as necessary to preserve the safe and efficient flow of air traffic within the National Airspace System (NAS).

History

The FAA published a notice of proposed rulemaking (NPRM) for Docket No. FAA–2022–0162 in the **Federal Register** (87 FR 12630; March 7, 2022), revoking Colored Federal airway G–15 due to the planned decommissioning of the St Marys, AK, and Takotna River, AK, NDBs. Interested parties were invited to participate in this rulemaking effort by submitting comments on the proposal. No comments were received.

Green Federal airways are published in paragraph 6009(a) of FAA Order JO 7400.11G, dated August 19, 2022, and effective September 15, 2022, which is incorporated by reference in 14 CFR 71.1. The Colored Federal airway listed in this document will be published subsequently in FAA Order JO 7400.11.

Availability and Summary of Documents for Incorporation by Reference

This document amends FAA Order JO 7400.11G, Airspace Designations and Reporting Points, 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. 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 revoking Colored Federal airway G–15 due to the decommissioning of the St Marys, AK, and Takotna River, AK, NDBs. The amendment is described below.

G–15: G–15 extends between the St Marys, AK, NDB and the Takotna River, AK, NDB. The airway is removed in its entirety.

FAA Order JO 7400.11, Airspace Designations and Reporting Points, is published yearly and effective on September 15.

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 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 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

The FAA has determined that this airspace action of revoking Colored Federal airway G–15, due to the planned decommissioning of the St Marys, AK, and Takotna River, AK, NDBs, 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), and paragraph 5–6.5k, which categorically excludes from further environmental review the publication of existing air traffic control procedures that do not essentially change existing tracks, create new tracks, change altitude, or change concentration of aircraft on these tracks. 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. Accordingly, 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 6009(a) Green Federal Airways.

* * * * *

G–15 [Removed]

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Issued in Washington, DC, on November 29, 2022.

Scott M. Rosenbloom,

Manager, Airspace Rules and Regulations.

[FR Doc. 2022–26376 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2022–0078; Airspace Docket No. 22–AAL–2]

RIN 2120–AA66

Revocation of Colored Federal Airway Amber 4 (A–4); Anaktuvuk Pass, AK

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action revokes Colored Federal airway Amber 4 (A–4) in the vicinity of Anaktuvuk Pass, AK, due to the pending decommissioning of the Anaktuvuk Pass, AK (AKP), Non-Directional Beacon (NDB).

DATES: Effective date 0901 UTC, February 23, 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: FAA Order JO 7400.11G, Airspace Designations and Reporting Points, and subsequent amendments can be viewed online at *www.faa.gov/air_traffic/publications/*. For further information, you can contact the Rules and Regulations Group, 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 modifies the route structure as necessary to preserve the safe and efficient flow of air traffic within the National Airspace System (NAS).

History

The FAA published a notice of proposed rulemaking (NPRM) for Docket No. FAA–2022–0078 in the **Federal Register** (87 FR 10991; February 28, 2022), revoking Colored Federal airway A–4 due to the planned decommissioning of the Anaktuvuk Pass, AK, NDB. Interested parties were invited to participate in this rulemaking effort by submitting comments on the proposal. No comments were received.

Amber Federal airways are published in paragraph 6009(c) of FAA Order JO 7400.11G, dated August 19, 2022, and effective September 15, 2022, which is incorporated by reference in 14 CFR 71.1. The Colored Federal airway listed in this document will be published subsequently in FAA Order JO 7400.11.

Availability and Summary of Documents for Incorporation by Reference

This document amends FAA Order JO 7400.11G, Airspace Designations and Reporting Points, 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. 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 revoking Colored Federal airway A–4 due to the decommissioning of the Anaktuvuk Pass, AK, NDB. The amendment is described below.

A–4: A–4 extends between the Evansville, AK, NDB and the Anaktuvuk Pass, AK, NDB. The airway is removed in its entirety.

FAA Order JO 7400.11, Airspace Designations and Reporting Points, is published yearly and effective on September 15.

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 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 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

The FAA has determined that this airspace action of revoking Colored Federal airway A–4, due to the planned decommissioning of the Anaktuvuk Pass, AK, NDB, 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), and paragraph 5–6.5k, which categorically excludes from further environmental review the publication of existing air traffic control procedures that do not essentially change existing tracks, create new tracks, change altitude, or change concentration of aircraft on these tracks. 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. Accordingly, 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 6009(c) Amber Federal airways.

* * * * *

A–4 [Removed]

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Issued in Washington, DC, on November 29, 2022.

Scott M. Rosenbloom,

Manager, Airspace Rules and Regulations.

[FR Doc. 2022–26377 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2022–0301; Airspace Docket No. 22–AAL–21]

RIN 2120–AA66

Revocation of Colored Federal Airway Green 7 (G–7); Nome, AK

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule.

SUMMARY: This action revokes Colored Federal airway Green 7 (G–7) due to the pending decommissioning of the Fort Davis, AK (FDV), Non-Directional Beacon (NDB) in the vicinity of Nome, AK.

DATES: Effective date 0901 UTC, February 23, 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: FAA Order JO 7400.11G, Airspace Designations and Reporting Points, and subsequent amendments can be viewed online at *www.faa.gov/air_traffic/publications/*. For further information, you can contact the Rules and Regulations Group, 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 modifies the route structure as necessary to preserve the safe and efficient flow of air traffic within the National Airspace System (NAS).

History

The FAA published a notice of proposed rulemaking (NPRM) for Docket No. FAA–2022–0301 in the **Federal Register** (87 FR 19413; April 4, 2022), revoking Colored Federal airway G–7 due to the planned decommissioning of the Fort Davis, AK, NDB in the vicinity of Nome, AK. Interested parties were invited to participate in this rulemaking effort by submitting comments on the proposal. One comment was received.

Green Federal airways are published in paragraph 6009(a) of FAA Order JO 7400.11G, dated August 19, 2022, and effective September 15, 2022, which is incorporated by reference in 14 CFR 71.1. The Colored Federal airway listed in this document will be published subsequently in FAA Order JO 7400.11.

Discussion of Comments

In the comment received, the commenter recognized the improved efficiency of the NAS provided by global positioning system (GPS) navigation, but was critical of the cost of installing the equipment into aircraft. The FAA appreciates the comment addressing the improved efficiency GPS provides the NAS and understands the pilot's frustration with the cost of avionics.

Although avionic equipment is costly, the FAA notes that GPS equipment costs have decreased in recent years; whereas the costs of automatic direction finder (ADF) equipment used to navigate via NDB-based Colored Federal airways have continued to increase. The higher ADF equipment costs and associated higher maintenance costs, especially in remote areas of Alaska, support the move away from NDB-based navigation.

The FAA also offers that the revocation of G–7 between the Gambell, AK, NDB and the Norton Bay, AK, NDB does not require GPS equipage as the revocation of G–7 is mitigated by two adjacent VHF Omnidirectional Range (VOR) Federal airways, V–414 and V–452, that extend between the Gambell, AK, NDB and the Norton Bay, AK, NDB. Additionally, the FAA accomplished a traffic study of the G–7 Colored Federal airway between the Gambell NDB and the Fort Davis, AK, NDB that showed no usage of G–7 in recent years. Instead, pilots used V–452 to navigate overwater between Gambell, AK, and Nome, AK; further demonstrating pilots will not require additional GPS equipage to mitigate the revocation of G–7.

Availability and Summary of Documents for Incorporation by Reference

This document amends FAA Order JO 7400.11G, Airspace Designations and Reporting Points, 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. 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 revoking Colored Federal airway G–7 due to the planned decommissioning of the Fort Davis, AK, NDB in the vicinity of Nome, AK. The amendment is described below.

G–7: G–7 extends between the Gambell, AK, NDB and the Norton Bay, AK, NDB. The airway is removed in its entirety.

FAA Order JO 7400.11, Airspace Designations and Reporting Points, is published yearly and effective on September 15.

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 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 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

The FAA has determined that this airspace action of revoking Colored Federal airway G–7, due to the planned decommissioning of the Fort Davis, AK, NDB, 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), and paragraph 5–6.5k, which categorically excludes from further environmental review the publication of existing air traffic control procedures that do not essentially change existing tracks, create new tracks, change altitude, or change concentration of aircraft on these tracks. 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. Accordingly, 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 6009(a) Green Federal Airways.

* * * * *

G–7 [Removed]

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Issued in Washington, DC, on November 30, 2022.

Scott M. Rosenbloom,

Manager, Airspace Rules and Regulations.

[FR Doc. 2022–26380 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 372

[EPA–HQ–OPPT–2022–0387; FRL–9529–03–OCSPP]

RIN 2070–AL09

Community Right-to-Know; Adopting 2022 North American Industry Classification System (NAICS) Codes for Toxics Release Inventory (TRI) Reporting; Correction

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; correction.

SUMMARY: The Environmental Protection Agency (EPA) is correcting a final rule that appeared in **Federal Register** on Monday, November 28, 2022, which finalized updates to the list of North American Industry Classification System (NAICS) codes subject to reporting under the Toxics Release Inventory (TRI) to reflect the Office of Management and Budget (OMB) 2022 NAICS code revision. This document corrects an error in an amendatory instruction that appeared in the regulatory text portion of the final rule.

DATES: This correction is effective on December 28, 2022.

FOR FURTHER INFORMATION CONTACT:

For technical information contact: Rachel Dean, Data Collection Branch, Data Gathering and Analysis Division (Mail code: 7406M), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave. NW, Washington, DC 20460; telephone number: (202) 566–1303; email address: *dean.rachel@epa.gov.*

For general information contact: The Emergency Planning and Community Right-to-Know Information Center; telephone number: (800) 424–9346 or (703) 348–5070 in the Washington, DC Area and International; website: *https://www.epa.gov//hotlines.*

SUPPLEMENTARY INFORMATION: EPA is correcting an inaccurate amendatory instruction in its final rule, FRL–9529–02–OCSPP, published November 28, 2022 (87 FR 72891), which finalized updates to the list of North American Industry Classification System (NAICS) codes subject to reporting under the Toxics Release Inventory (TRI) to reflect the Office of Management and Budget (OMB) 2022 NAICS code revision.

Correction

In FR Doc. 2022–25375, appearing on page 72891 in the **Federal Register** of Monday, November 28, 2022, the following correction is made:

1. On page 72896, in the second column, amendatory instruction 2 is corrected to read as follows:

''2. Amend § 372.22 by revising the introductory text and paragraph (b) introductory text and adding paragraph (d) to read as follows:''

Dated: November 29, 2022.

Michal Freedhoff,

Assistant Administrator, Office of Chemical Safety and Pollution Prevention.

[FR Doc. 2022–26393 Filed 12–5–22; 8:45 am]

BILLING CODE 6560–50–P

Proposed Rules

Federal Register

Vol. 87, No. 233

Tuesday, December 6, 2022

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 39

[Docket No. FAA–2022–1491; Project Identifier MCAI–2022–00924–T]

RIN 2120–AA64

Airworthiness Directives; Airbus SAS Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to adopt a new airworthiness directive (AD) for all Airbus SAS Model A318 series airplanes; Model A319 series airplanes; Model A320–211, –212, –214, –216, –231, –232, –233, –251N, –252N, –253N, –271N, –272N, and –273N airplanes; and Model A321 series airplanes. This proposed AD was prompted by a report that certain overheat detection system (OHDS) sensing elements installed at certain positions might not properly detect thermal bleed leak events due to a quality escape during the manufacturing process. This proposed AD would require a one-time detailed inspection of each affected part installed at an affected position and, depending on the findings, replacement; and would prohibit the installation of affected parts at affected positions, as specified in a European Union Aviation Safety Agency (EASA) AD, which is proposed for incorporation by reference. The FAA is proposing this AD to address the unsafe condition on these products.

DATES: The FAA must receive comments on this proposed AD by January 20, 2023.

ADDRESSES: You may send comments, using the procedures found in 14 CFR 11.43 and 11.45, by any of the following methods:

- *Federal eRulemaking Portal:* Go to *regulations.gov*. Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

AD Docket: You may examine the AD docket at *regulations.gov* under Docket No. FAA–2022–1491; 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 NPRM, the mandatory continuing airworthiness information (MCAI), any comments received, and other information. The street address for Docket Operations is listed above.

Material Incorporated by Reference:

- For EASA material that will be incorporated by reference (IBR) in this AD, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; telephone +49 221 8999 000; email *ADs@easa.europa.eu;* website *easa.europa.eu.* You may find this material on the EASA website *easa.europa.eu.* It is also available in the AD docket at *regulations.gov* by searching for and locating Docket No. FAA–2022–1491.
- For Kidde Aerospace & Defense service information identified in this proposed AD, contact Kidde Aerospace & Defense, 4200 Airport Drive NW, Wilson, NC 27896; phone: 252–246–7134; fax: 252–246–7181; email: *avionicssupport@collins.com;* website *kiddeaerospace.com.*
- You may view this material at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195.

FOR FURTHER INFORMATION CONTACT: Hyeyoon Jang, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th Street, Des Moines, WA 98198; telephone 817–222–5584; email *hye.yoon.jang@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

The FAA invites you to send any written relevant data, views, or arguments about this proposal. Send your comments to an address listed under **ADDRESSES**. Include ‘‘Docket No. FAA–2022–1491; Project Identifier MCAI–2022–00924–T’’ at the beginning of your comments. The most helpful comments reference a specific portion of the proposal, explain the reason for any recommended change, and include supporting data. The FAA will consider all comments received by the closing date and may amend this proposal because of those comments.

Except for Confidential Business Information (CBI) as described in the following paragraph, and other information as described in 14 CFR 11.35, the FAA will post all comments received, without change, to *regulations.gov*, including any personal information you provide. The agency will also post a report summarizing each substantive verbal contact received about this NPRM.

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 NPRM 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 NPRM, it is important that you clearly designate the submitted comments as CBI. Please mark each page of your submission containing CBI as ‘‘PROPIN.’’ The FAA will treat such marked submissions as confidential under the FOIA, and they will not be placed in the public docket of this NPRM. Submissions containing CBI should be sent to Hyeyoon Jang, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th Street, Des Moines, WA 98198; telephone 817–222–5584; email *hye.yoon.jang@faa.gov.* Any commentary that the FAA receives which is not specifically designated as CBI will be placed in the public docket for this rulemaking.

Background

EASA, which is the Technical Agent for the Member States of the European Union, has issued EASA AD 2022–0147, dated July 14, 2022; corrected August 17, 2022 (EASA AD 2022–0147) (also referred to as the MCAI), to correct an unsafe condition for all Airbus SAS

Model A318 series airplanes; Model A319 series airplanes; Model A320–211, –212, –214, –215, –216, –231, –232, –233, –251N, –252N, –253N, –271N, –272N, and –273N airplanes; and Model A321 series airplanes. Model A320–215 airplanes are not certificated by the FAA and are not included on the U.S. type certificate data sheet; this proposed AD therefore does not include those airplanes in the applicability.

The MCAI states that the affected part manufacturer, Kidde Aerospace & Defense, reported that certain OHDS sensing elements, produced before January 31, 2021, may not properly detect thermal bleed leak events due to a quality escape during the manufacturing process. The MCAI states that the unsafe condition, if not addressed, could result in an air leak remaining undetected by the OHDS at an affected position (*i.e.,* a position identified as functional item number (FIN) 34HF, FIN 35HF, FIN 61HF or FIN 62HF) and not being isolated during flight, possibly resulting in localized areas of the main landing gear bay and keel beam being exposed to high temperatures, and consequent reduced structural integrity of the airplane.

The FAA is proposing this AD to address the unsafe condition on these products. You may examine the MCAI in the AD docket at regulations.gov under Docket No. FAA–2022–1491.

Related Service Information Under 1 CFR Part 51

EASA AD 2022–0147 specifies procedures for a one-time special detailed inspection (SDI) of each OHDS sensing element installed at an affected position to detect discrepancies (an incorrect electronic centralized aircraft monitor (ECAM) alert (one not related to AIR L WING LEAK) being displayed following the inspection of any OHDS sensing element) and, depending on findings, replacement of any affected part with a serviceable part. EASA AD 2022–0147 also prohibits the installation of affected parts at affected positions.

Kidde Aerospace & Defense Service Bulletin CFD–26–3, dated January 13, 2022; and Revision 1, dated March 29, 2022, specify the part numbers and corresponding date codes of the affected OHDS sensing elements.

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 the **ADDRESSES** section.

FAA's Determination

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 the State of Design Authority, it has notified the FAA of the unsafe condition described in the MCAI and service information referenced above. The FAA is issuing this NPRM after determining that the unsafe condition described previously is likely to exist or develop in other products of these same type designs.

Proposed AD Requirements in This NPRM

This proposed AD would require accomplishing the actions specified in EASA AD 2022–0147 described previously, except for any differences identified as exceptions in the regulatory text of this proposed AD.

Explanation of Required Compliance Information

In the FAA's ongoing efforts to improve the efficiency of the AD process, the FAA developed a process to use some civil aviation authority (CAA) ADs as the primary source of information for compliance with requirements for corresponding FAA ADs. The FAA has been coordinating this process with manufacturers and CAAs. As a result, the FAA proposes to incorporate EASA AD 2022–0147 by reference in the FAA final rule. This proposed AD would, therefore, require compliance with EASA AD 2022–0147 in its entirety through that incorporation, except for any differences identified as exceptions in the regulatory text of this proposed AD. Using common terms that are the same as the heading of a particular section in EASA AD 2022–0147 does not mean that operators need comply only with that section. For example, where the AD requirement refers to "all required actions and compliance times," compliance with this AD requirement is not limited to the section titled "Required Action(s) and Compliance Time(s)" in EASA AD 2022–0147. Service information required by EASA AD 2022–0147 for compliance will be available at regulations.gov by searching for and locating Docket No. FAA–2022–1491 after the FAA final rule is published.

Costs of Compliance

The FAA estimates that this proposed AD would affect 1,836 airplanes of U.S. registry. The FAA estimates the following costs to comply with this proposed AD:

ESTIMATED COSTS FOR REQUIRED ACTIONS

Labor cost	Parts cost	Cost per product	Cost on U.S. operators
6 work-hours × $85 per hour = $510	$0	$510	$936,360

The FAA estimates the following costs to do any necessary on-condition action that would be required based on the results of any required actions. The FAA has no way of determining the number of aircraft that might need this on-condition action:

ESTIMATED COSTS OF ON-CONDITION ACTIONS

Labor cost	Parts cost	Cost per product
1 work-hour × $85 per hour = $85	$1,645	$1,730 (per OHDS sensing element).

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

Authority for This Rulemaking

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

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

Regulatory Findings

The FAA determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would 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 this proposed regulation:

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

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

(3) Would 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 Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 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:

Airbus SAS: Docket No. FAA–2022–1491; Project Identifier MCAI–2022–00924–T.

(a) Comments Due Date

The FAA must receive comments on this airworthiness directive (AD) by January 20, 2023.

(b) Affected ADs

None.

(c) Applicability

This AD applies to all Airbus SAS airplanes, certificated in any category, as identified in paragraphs (c)(1) through (4) of this AD.

(1) Model A318–111, –112, –121, and –122 airplanes.

(2) Model A319–111, –112, –113, –114, –115, –131, –132, –133, –151N, –153N, and –171N airplanes.

(3) Model A320–211, –212, –214, –216, –231, –232, –233, –251N, –252N, –253N, –271N, –272N, and –273N airplanes.

(4) Model A321–111, –112, –131, –211, –212, –213, –231, –232, –251N, –252N, –253N, –271N, –272N, –251NX, –252NX, –253NX, –271NX, and –272NX airplanes.

(d) Subject

Air Transport Association (ATA) of America Code 36, Pneumatic.

(e) Unsafe Condition

This AD was prompted by a report that certain overheat detection system (OHDS) sensing elements installed at certain positions might not properly detect thermal bleed leak events due to a quality escape during the manufacturing process. The FAA is issuing this AD to address OHDS sensing elements that do not properly detect thermal bleed leak events. The unsafe condition, if not addressed, could result in an air leak remaining undetected by the OHDS at an affected position and not being isolated during flight, possibly resulting in localized areas of the main landing gear bay and keel beam being exposed to high temperatures, and consequent reduced structural integrity of the airplane.

(f) Compliance

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

(g) Requirements

Except as specified in paragraph (h) of this AD: Comply with all required actions and compliance times specified in, and in accordance with, European Union Aviation Safety Agency (EASA) AD 2022–0147, dated July 14, 2022; corrected August 17, 2022 (EASA AD 2022–0147).

(h) Exceptions to EASA AD 2022–0147

(1) Where EASA AD 2022–0147 defines ''Affected part'' and identifies part numbers and corresponding date codes as those ''listed in Section 1.A of the VSB,'' for this AD, those part numbers and corresponding date codes are listed in Section 1.A. of Kidde Aerospace & Defense Service Bulletin CFD–26–3, dated January 13, 2022; or Revision 1, dated March 29, 2022.

(2) Where EASA AD 2022–0147 refers to its effective date, this AD requires using the effective date of this AD.

(3) Where paragraph (2) of EASA AD 2022–0147 refers to ''any discrepancy as defined in the SB,'' for this AD, a discrepancy is an incorrect electronic centralized aircraft monitor (ECAM) alert (one not related to AIR L WING LEAK) being displayed following the inspection of any OHDS sensing element.

(4) Where the service information referenced in EASA AD 2022–0147 specifies to send an affected part to the manufacturer, this AD does not include that requirement.

(5) This AD does not adopt the ''Remarks'' section of EASA AD 2022–0147.

(i) No Reporting Requirement

Although the service information referenced in EASA AD 2022–0147 specifies to submit certain information to the manufacturer, this AD does not include that requirement.

(j) Additional AD Provisions

The following provisions also apply to this AD:

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

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

(3) *Required for Compliance (RC):* Except as required by paragraph (j)(2) of this AD, if any service information contains procedures or tests that are identified as RC, those procedures and tests must be done to comply with this AD; any procedures or tests that are not identified as RC are recommended. Those procedures and tests that are not identified as RC may be deviated from using accepted methods in accordance with the operator's maintenance or inspection program without obtaining approval of an AMOC, provided the procedures and tests identified as RC can be done and the airplane can be put back in an airworthy condition. Any substitutions or changes to procedures or tests identified as RC require approval of an AMOC.

(k) Additional Information

For more information about this AD, contact Hyeyoon Jang, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th Street, Des Moines, WA 98198; telephone 817–222–5584; email *hye.yoon.jang@faa.gov.*

(l) Material Incorporated by Reference

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

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

(i) European Union Aviation Safety Agency (EASA) AD 2022–0147, dated July 14, 2022; corrected August 17, 2022.

(ii) Kidde Aerospace & Defense Service Bulletin CFD–26–3, dated January 13, 2022.

(iii) Kidde Aerospace & Defense Service Bulletin CFD–26–3, Revision 1, dated March 29, 2022.

(3) For EASA AD 2022–0147, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; telephone +49 221 8999 000; email *ADs@easa.europa.eu;* website *easa.europa.eu.* You may find this EASA AD on the EASA website at *ad.easa.europa.eu.*

(4) For Kidde Aerospace & Defense service information identified in this AD, contact Kidde Aerospace & Defense, 4200 Airport Drive NW, Wilson, NC 27896; phone: 252–246–7134; fax: 252–246–7181; email: *avionicssupport@collins.com;* website *kiddeaerospace.com.*

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

(6) 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 November 29, 2022.

Christina Underwood,

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

[FR Doc. 2022–26409 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2022–1492; Project Identifier MCAI–2022–01184–T]

RIN 2120–AA64

Airworthiness Directives; Airbus Canada Limited Partnership (Type Certificate Previously Held by C Series Aircraft Limited Partnership (CSALP); Bombardier, Inc.) Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to adopt a new airworthiness directive (AD) for certain Airbus Canada Limited Partnership Model BD–500–1A10 airplanes. This proposed AD was prompted by reports the overwing emergency exit door (OWEED) escape line may be incorrectly routed. This proposed AD would require inspecting the OWEED escape line and correcting the routing if required, as specified in a Transport Canada AD, which is proposed for incorporation by reference (IBR). The FAA is proposing this AD to address the unsafe condition on these products.

DATES: The FAA must receive comments on this proposed AD by January 20, 2023.

ADDRESSES: You may send comments, using the procedures found in 14 CFR 11.43 and 11.45, by any of the following methods:

- *Federal eRulemaking Portal:* Go to *regulations.gov.* Follow the instructions for submitting comments.
- *Fax:* (202) 493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

AD Docket: You may examine the AD docket at *regulations.gov* under Docket No. FAA–2022–1492; 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 NPRM, the mandatory continuing airworthiness information (MCAI), any comments received, and other information. The street address for Docket Operations is listed above.

Material Incorporated by Reference:

- For material that is proposed for IBR in this NPRM, contact Transport Canada National Aircraft Certification, 159 Cleopatra Drive, Nepean, Ontario K1A 0N5, Canada; telephone (888) 663–3639; email *AD-CN@tc.gc.ca;* website *tc.canada.ca/en/aviation.*
- You may view this service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call (206) 231–3195.

FOR FURTHER INFORMATION CONTACT: Chirayu Gupta, Aerospace Engineer, Mechanical Systems and Administrative Services Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone (516) 228–7300; email *9-avs-nyaco-cos@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

The FAA invites you to send any written relevant data, views, or arguments about this proposal. Send your comments to an address listed under **ADDRESSES**. Include ''Docket No. FAA–2022–1492; Project Identifier MCAI–2022–01184–T'' at the beginning of your comments. The most helpful comments reference a specific portion of the proposal, explain the reason for any recommended change, and include supporting data. The FAA will consider all comments received by the closing date and may amend this proposal because of those comments.

Except for Confidential Business Information (CBI) as described in the following paragraph, and other information as described in 14 CFR 11.35, the FAA will post all comments received, without change, to *regulations.gov*, including any personal information you provide. The agency will also post a report summarizing each substantive verbal contact received about this NPRM.

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 NPRM 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 NPRM, it is important that you clearly designate the submitted comments as CBI. Please mark each page of your submission containing CBI as ''PROPIN.'' The FAA will treat such marked submissions as confidential under the FOIA, and they will not be placed in the public docket of this NPRM. Submissions containing CBI should be sent to Chirayu Gupta, Aerospace Engineer, Mechanical Systems and Administrative Services Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone (516) 228–7300; email *9-avs-nyaco-cos@faa.gov.* Any commentary that the FAA receives which is not specifically designated as CBI will be placed in the public docket for this rulemaking.

Background

Transport Canada, which is the aviation authority for Canada, has issued AD CF–2022–51, dated

September 13, 2022 (Transport Canada AD CF–2022–51) (also referred to as the MCAI), to correct an unsafe condition for certain Airbus Canada Limited Partnership Model BD–500–1A10 airplanes. The MCAI states certain airplanes may have entered service with the OWEED escape line incorrectly routed, in a manner that would render it inoperable when needed. The OWEED escape line is used to facilitate passenger egress along the wings following a ditching event. It is possible for the OWEED escape line to be installed under the liner of the OWEED resulting in the escape line not deploying, which could cause possible injuries to passengers escaping over the wing following a ditching event.

You may examine the MCAI in the AD docket at *regulations.gov* under Docket No. FAA–2022–1492.

Related Service Information Under 1 CFR Part 51

Transport Canada AD CF–2022–51 specifies procedures for doing a detailed inspection of the OWEED escape line routing and correcting the OWEED escape line routing, if required. 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**.

FAA's Determination

This product has been approved by the aviation authority of another country and is approved for operation in the United States. Pursuant to the FAA's bilateral agreement with the State of Design Authority, it has notified the FAA of the unsafe condition described in the MCAI described above. The FAA is issuing this NPRM after determining that the unsafe condition described previously is likely to exist or develop in other products of the same type design.

Proposed AD Requirements in This NPRM

This proposed AD would require accomplishing the actions specified in Transport Canada AD CF–2022–51 described previously, except for any differences identified as exceptions in the regulatory text of this proposed AD.

Explanation of Required Compliance Information

In the FAA's ongoing efforts to improve the efficiency of the AD process, the FAA developed a process to use some civil aviation authority (CAA) ADs as the primary source of information for compliance with requirements for corresponding FAA ADs. The FAA has been coordinating this process with manufacturers and CAAs. As a result, the FAA proposes to incorporate Transport Canada AD CF–2022–51 by reference in the FAA final rule. This proposed AD would, therefore, require compliance with Transport Canada AD CF–2022–51 in its entirety through that incorporation, except for any differences identified as exceptions in the regulatory text of this proposed AD. Service information required by Transport Canada AD CF–2022–51 for compliance will be available at *regulations.gov* under Docket No. FAA–2022–1492 after the FAA final rule is published.

Costs of Compliance

The FAA estimates that this AD, if adopted as proposed, would affect 4 airplanes of U.S. registry. The FAA estimates the following costs to comply with this proposed AD:

ESTIMATED COSTS FOR REQUIRED ACTIONS

Labor cost	Parts cost	Cost per product	Cost on U.S. operators
1.5 work-hours × $85 per hour = $128	$0	$128	$512

The FAA estimates the following costs to do any necessary on-condition action that would be required based on the results of any required actions. The FAA has no way of determining the number of aircraft that might need this on-condition action:

ESTIMATED COSTS OF ON-CONDITION ACTIONS

Labor cost	Parts cost	Cost per product
1 work-hour × $85 per hour = $85	$0	$85

Authority for This Rulemaking

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

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

Regulatory Findings

The FAA determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would 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 this proposed regulation:

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

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

(3) Would 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 Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 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:

Airbus Canada Limited Partnership (Type Certificate Previously Held by C Series Aircraft Limited Partnership (CSALP); Bombardier, Inc.): Docket No. FAA–2022–1492; Project Identifier MCAI–2022–01184–T.

(a) Comments Due Date

The FAA must receive comments on this airworthiness directive (AD) by January 20, 2023.

(b) Affected ADs

None.

(c) Applicability

This AD applies to Airbus Canada Limited Partnership (Type Certificate previously held by C Series Aircraft Limited Partnership (CSALP); Bombardier, Inc.) Model BD–500–1A10 airplanes, certificated in any category, as identified in Transport Canada AD CF–2022–51, dated September 13, 2022 (Transport Canada AD CF–2022–51).

(d) Subject

Air Transport Association (ATA) of America Code: 25, Equipment/furnishings.

(e) Unsafe Condition

This AD was prompted by reports the overwing emergency exit door (OWEED) escape line may be incorrectly installed. The FAA is issuing this AD to ensure the OWEED escape line is installed correctly. The unsafe condition, if not addressed, could result in the OWEED escape line not deploying, resulting in possible passenger injury following a ditching event.

(f) Compliance

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

(g) Requirements

Except as specified in paragraph (h) of this AD: Comply with all required actions and compliance times specified in, and in accordance with, Transport Canada AD CF–2022–51.

(h) Exception to Transport Canada AD CF–2022–51

Where Transport Canada AD CF–2022–51 refers to its effective date, this AD requires using the effective date of this AD.

(i) Additional AD Provisions

The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, New York ACO Branch, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or responsible Flight Standards Office, as appropriate. If sending information directly to the manager of the certification office, send it to ATTN: Program Manager, Continuing Operational Safety, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone (516) 228–7300. Before using any approved AMOC, notify your appropriate principal inspector, or lacking a principal inspector, the manager of the responsible Flight Standards Office.

(2) *Contacting the Manufacturer:* For any requirement in this AD to obtain instructions from a manufacturer, the instructions must be accomplished using a method approved by the Manager, New York ACO Branch, FAA; or Transport Canada; or Airbus Canada Limited Partnership's Transport Canada Design Organization Approval (DOA). If approved by the DOA, the approval must include the DOA-authorized signature.

(3) *Required for Compliance (RC):* Except as required by paragraph (i)(2) of this AD, if any service information contains procedures or tests that are identified as RC, those procedures and tests must be done to comply with this AD; any procedures or tests that are not identified as RC are recommended. Those procedures and tests that are not identified as RC may be deviated from using accepted methods in accordance with the operator's maintenance or inspection program without obtaining approval of an AMOC, provided the procedures and tests identified as RC can be done and the airplane can be put back in an airworthy condition. Any substitutions or changes to procedures or tests identified as RC require approval of an AMOC.

(j) Additional Information

For more information about this AD, contact Chirayu Gupta, Aerospace Engineer, Mechanical Systems and Administrative Services Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone (516) 228–7300; email *9-avs-nyaco-cos@faa.gov.*

(k) Material Incorporated by Reference

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

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

(i) Transport Canada AD CF–2022–51, dated September 13, 2022.

(ii) [Reserved]

(3) For Transport Canada AD CF–2022–51, contact Transport Canada National Aircraft Certification, 159 Cleopatra Drive, Nepean, Ontario K1A 0N5, Canada; telephone (888) 663–3639; email *AD-CN@tc.gc.ca;* website *tc.canada.ca/en/aviation.*

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

(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 November 29, 2022.

Christina Underwood,

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

[FR Doc. 2022–26408 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2022–1171; Project Identifier AD–2022–00852–T]

RIN 2120–AA64

Airworthiness Directives; The Boeing Company Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to supersede Airworthiness Directive (AD) 2021–08–19, which applies to all The Boeing Company Model 787–8, –9, and –10 airplanes. AD 2021–08–19 requires repetitive general visual inspections for disengaged or damaged decompression panels of the bilge barriers located in the forward and aft cargo compartments, reinstallation of disengaged but undamaged panels, and replacement of damaged panels. Since the FAA issued AD 2021–08–19, new procedures for changing or replacing the bilge barrier assembly in the forward cargo compartment have been developed. This proposed AD would retain the requirements of AD 2021–08–19 and require changing or replacing the bilge barrier assembly in the forward and aft cargo compartments, which would terminate the repetitive inspections. The FAA is proposing this AD to address the unsafe condition on these products.

DATES: The FAA must receive comments on this proposed AD by January 20, 2023.

ADDRESSES: You may send comments, using the procedures found in 14 CFR 11.43 and 11.45, by any of the following methods:

- *Federal eRulemaking Portal:* Go to *regulations.gov*. Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this NPRM, contact Boeing Commercial Airplanes, Attention: Contractual & Data Services (C&DS), 2600 Westminster Blvd., MC 110–SK57, Seal Beach, CA 90740–5600; telephone 562–797–1717; internet *myboeingfleet.com*. You may view this service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195. It is also available at *regulations.gov* by searching for and locating Docket No. FAA–2022–1171.

Examining the AD Docket

You may examine the AD docket at *regulations.gov* by searching for and locating Docket No. FAA–2022–1171; 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 NPRM, any comments received, and other information. The street address for Docket Operations is listed above.

FOR FURTHER INFORMATION CONTACT: Brandon Lucero, Aerospace Engineer, Cabin Safety and Environmental Systems Section, FAA, Seattle ACO Branch, 2200 South 216th St., Des Moines, WA 98198; phone and fax: 206–231–3569; email: *brandon.lucero@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

The FAA invites you to send any written relevant data, views, or arguments about this proposal. Send your comments to an address listed under **ADDRESSES**. Include ‘‘Docket No. FAA–2022–1171; Project Identifier AD–2022–00852–T’’ at the beginning of your comments. The most helpful comments reference a specific portion of the proposal, explain the reason for any recommended change, and include supporting data. The FAA will consider all comments received by the closing date and may amend the proposal because of those comments.

Except for Confidential Business Information (CBI) as described in the following paragraph, and other information as described in 14 CFR 11.35, the FAA will post all comments received, without change, to *regulations.gov*, including any personal information you provide. The agency will also post a report summarizing each substantive verbal contact received about this proposed AD.

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 NPRM 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 NPRM, it is important that you clearly designate the submitted comments as CBI. Please mark each page of your submission containing CBI as ‘‘PROPIN.’’ The FAA will treat such marked submissions as confidential under the FOIA, and they will not be placed in the public docket of this NPRM. Submissions containing CBI should be sent to Brandon Lucero, Aerospace Engineer, Cabin Safety and Environmental Systems Section, FAA, Seattle ACO Branch, 2200 South 216th St., Des Moines, WA 98198; phone and fax: 206–231–3569; email: *brandon.lucero@faa.gov.* Any commentary that the FAA receives that is not specifically designated as CBI will be placed in the public docket for this rulemaking.

Background

The FAA issued AD 2021–08–19, Amendment 39–21513 (86 FR 20440, April 20, 2021) (AD 2021–08–19), for all The Boeing Company Model 787–8, –9, and –10 airplanes. AD 2021–08–19 was prompted by reports of multiple incidents of torn decompression panels found in the bilge area, and the determination that additional airplanes are subject to the unsafe condition. AD 2021–08–19 requires repetitive general visual inspections for disengaged or damaged decompression panels of the bilge barriers located in the forward and aft cargo compartments, reinstallation of disengaged but undamaged panels, and replacement of damaged panels. The FAA issued AD 2021–08–19 to address the possibility of leakage in the bilge area, which could, in the event of a cargo fire, result in insufficient Halon concentrations to adequately control the fire. This condition, if not addressed, could result in the loss of continued safe flight and landing of the airplane.

Actions Since AD 2021–08–19 Was Issued

The preamble to AD 2021–08–19 specifies that the FAA considers that AD ‘‘interim action’’ and that the FAA might consider further rulemaking if a modification is developed, approved, and available. The manufacturer has since developed such a modification (procedures for changing or replacing the bilge barrier assembly in the forward cargo compartment), which would terminate the repetitive inspections required by AD 2021–08–19. The FAA has determined that this modification should be required.

FAA's Determination

The FAA is issuing this NPRM after determining that the unsafe condition described previously is likely to exist or develop on other products of the same type design.

Related Service Information Under 1 CFR Part 51

The FAA reviewed Boeing Alert Requirements Bulletin B787–81205–SB500011–00 RB, Issue 001, dated May 10, 2022. This service information specifies procedures for changing or replacing the bilge barrier assembly in the forward cargo compartments at stations (STA) 345 and 825 and aft cargo compartment at STA 1304. This service information is reasonably available because the interested parties have access to it through their normal course of business or by the means identified in the **ADDRESSES** section.

Proposed AD Requirements in This NPRM

This proposed AD would retain all of the requirements of AD 2021–08–19. This proposed AD would also require accomplishing the actions identified in Boeing Alert Requirements Bulletin B787–81205–SB500011–00 RB, Issue 001, dated May 10, 2022, described previously, except for any differences identified as exceptions in the regulatory text of this proposed AD.

For information on the procedures and compliance times, see this service information at *regulations.gov* by searching for and locating Docket No. FAA–2022–1171.

Costs of Compliance

The FAA estimates that this AD, if adopted as proposed, would affect 135 airplanes of U.S. registry. The FAA estimates the following costs to comply with this proposed AD:

ESTIMATED COSTS

Action	Labor cost	Parts cost	Cost per product	Cost on U.S. operators
Repetitive inspections (retained actions).	3 work-hours × $85 per hour = $255 per inspection cycle.	$0	$255 per inspection cycle	$34,425 per inspection cycle.
Change or replace bilge barrier (new proposed action).	Up to 7 work-hours × $85 per hour = $595.	Up to $12,100	Up to $12,695	Up to $1,713,825.

The FAA estimates the following costs to do any necessary replacements that would be required based on the results of the proposed inspection. The agency has no way of determining the number of aircraft that might need these replacements:

ON-CONDITION COSTS

Action	Labor cost	Parts cost	Cost per product
Replacement (retained requirement)	1 work-hour × $85 per hour = $85	$ *	$85

* The FAA has received no definitive data on which to base the parts costs estimates for the replacements.

Authority for This Rulemaking

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

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

Regulatory Findings

The FAA has determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would 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 the proposed regulation:

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

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

(3) Would 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 Proposed Amendment

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

PART 39—AIRWORTHINESS DIRECTIVES

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

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

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by:

■ a. Removing Airworthiness Directive (AD) 2021–08–19, Amendment 39–21513 (86 FR 20440, April 20, 2021), and

■ b. Adding the following new AD:

The Boeing Company: Docket No. FAA–2022–1171; Project Identifier AD–2022–00852–T.

(a) Comments Due Date

The FAA must receive comments on this airworthiness directive (AD) action by January 20, 2023.

(b) Affected ADs

This AD replaces AD 2021–08–19, Amendment 39–21513 (86 FR 20440, April 20, 2021) (AD 2021–08–19).

(c) Applicability

This AD applies to all The Boeing Company Model 787–8, –9, and –10 airplanes, certificated in any category.

(d) Subject

Air Transport Association (ATA) of America Code 50, Cargo and accessory compartments.

(e) Unsafe Condition

This AD was prompted by reports of multiple incidents of torn decompression panels being found in the bilge area, and the development of new procedures for changing or replacing the bilge barrier assembly in the forward cargo compartment. The FAA is issuing this AD to address the possibility of leakage in the bilge area, which could, in the event of a cargo fire, result in insufficient Halon concentrations to adequately control the fire. This condition, if not addressed, could result in the loss of continued safe flight and landing of the airplane.

(f) Compliance

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

(g) Retained Repetitive Inspections and Corrective Action With No Changes

This paragraph restates the requirements of paragraph (g) of AD 2021–08–19 with no changes. At the applicable times specified in paragraph (g)(1) or (2) of this AD: Do a general visual inspection for disengaged or damaged (torn) decompression panels of the bilge barriers located in the forward and aft cargo compartments. If any disengaged but undamaged panel is found: Before further flight, reinstall the panel. If any damaged panel is found: Before further flight, replace the panel with a new or serviceable panel. Reinstallations and replacements must be done in accordance with the operator's maintenance or inspection program, as applicable.

(1) If a general visual inspection for disengaged or damaged (torn) decompression panels of the bilge barriers was done before May 5, 2021 (the effective date of AD 2021–08–19): Do the next inspection within 4 calendar months after the most recent inspection. Repeat the inspection thereafter at intervals not to exceed 4 calendar months.

(2) If a general visual inspection for disengaged or damaged (torn) decompression panels of the bilge barriers was not done before May 5, 2021 (the effective date of AD 2021–08–19): Do the initial inspection within 30 days after May 5, 2021. Repeat the inspection thereafter at intervals not to exceed 4 calendar months.

(h) Retained MEL Provisions With No Changes

This paragraph restates the provisions of paragraph (h) of AD 2021–08–19 with no changes. If any decompression panel inspected as required by this AD is disengaged or damaged, the airplane may be operated as specified in the operator's existing FAA-approved minimum equipment list (MEL), provided provisions that address the disengaged or damaged decompression panels are included in the MEL.

(i) New Required Actions

Except as specified by paragraph (j) of this AD: At the applicable times specified in the "Compliance," paragraph of Boeing Alert Requirements Bulletin B787–81205–SB500011–00 RB, Issue 001, dated May 10, 2022, do all applicable actions identified in, and in accordance with, the Accomplishment Instructions of Boeing Alert Requirements Bulletin B787–81205–SB500011–00 RB, Issue 001, dated May 10, 2022. Accomplishing the actions required by this paragraph terminates the repetitive inspections required by paragraph (g) of this AD.

Note 1 to paragraph (i): Guidance for accomplishing the actions required by this AD can be found in Boeing Alert Service Bulletin B787–81205–SB500011–00, Issue 001, dated May 10, 2022, which is referred to in Boeing Alert Requirements Bulletin B787–81205–SB500011–00 RB, Issue 001, dated May 10, 2022.

(j) Exceptions to Service Information Specifications

Where the Compliance Time column of the table in the "Compliance" paragraph of Boeing Alert Requirements Bulletin B787–81205–SB500011–00 RB, Issue 001, dated May 10, 2022, uses the phrase "the Issue 001 date of Requirements Bulletin B787–81205–SB500011–00 RB," this AD requires using "the effective date of this AD."

(k) Alternative Methods of Compliance (AMOCs)

(1) The Manager, Seattle ACO Branch, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or responsible Flight Standards Office, as appropriate. If sending information directly to the manager of the certification office, send it to the attention of the person identified in paragraph (l)(1) of this AD. Information may be emailed to: *9-ANM-Seattle-ACO-AMOC-Requests@faa.gov.*

(2) Before using any approved AMOC, notify your appropriate principal inspector, or lacking a principal inspector, the manager of the responsible Flight Standards Office.

(3) An AMOC that provides an acceptable level of safety may be used for any repair, modification, or alteration required by this AD if it is approved by The Boeing Company Organization Designation Authorization (ODA) that has been authorized by the Manager, Seattle ACO Branch, FAA, to make those findings. To be approved, the repair method, modification deviation, or alteration deviation must meet the certification basis of the airplane, and the approval must specifically refer to this AD.

(4) AMOCs approved for AD 2021–08–19 are approved as AMOCs for the corresponding provisions of Boeing Alert Requirements Bulletin B787–81205–SB500011–00 RB, Issue 001, dated May 10, 2022, that are required by paragraph (i) of this AD.

(l) Related Information

(1) For more information about this AD, contact Brandon Lucero, Aerospace Engineer, Cabin Safety and Environmental Systems Section, FAA, Seattle ACO Branch, 2200 South 216th St., Des Moines, WA 98198; phone and fax: 206–231–3569; email: *brandon.lucero@faa.gov.*

(2) For service information identified in this AD, contact Boeing Commercial Airplanes, Attention: Contractual & Data Services (C&DS), 2600 Westminster Blvd., MC 110–SK57, Seal Beach, CA 90740–5600; telephone 562–797–1717; internet *myboeingfleet.com.* You may view this referenced service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195.

Issued on September 21, 2022.

Christina Underwood,

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

[FR Doc. 2022–26466 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2022–1566; Project Identifier MCAI–2022–00290–T]

RIN 2120–AA64

Airworthiness Directives; Airbus Canada Limited Partnership (Type Certificate Previously Held by C Series Aircraft Limited Partnership (CSALP); Bombardier, Inc.) Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to adopt a new airworthiness directive (AD) for all Airbus Canada Limited Partnership Model BD–500–1A10 and BD–500–1A11 airplanes. This proposed AD was prompted by reports of mechanical wear damage found on the engine fuel feed system tubes and fuel tube connections. This proposed AD would require repetitive inspections of the fuel feed system for damage and replacement if necessary, as specified in a Transport Canada AD, which is proposed for incorporation by reference (IBR). The FAA is proposing this AD to address the unsafe condition on these products.

DATES: The FAA must receive comments on this proposed AD by January 20, 2023.

ADDRESSES: You may send comments, using the procedures found in 14 CFR 11.43 and 11.45, by any of the following methods:

- *Federal eRulemaking Portal:* Go to *regulations.gov.* Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

AD Docket: You may examine the AD docket at *regulations.gov* under Docket No. FAA–2022–1566; 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 NPRM, the mandatory continuing airworthiness information (MCAI), any comments received, and other information. The street address for Docket Operations is listed above.

Material Incorporated by Reference:

• For material that is proposed for IBR in this NPRM contact Transport Canada, Transport Canada National Aircraft Certification, 159 Cleopatra Drive, Nepean, Ontario K1A 0N5, Canada; telephone 888–663–3639; email *AD-CN@tc.gc.ca;* website *tc.canada.ca/en/aviation.* It is also available at *regulations.gov* under Docket No. FAA–2022–1566.

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

FOR FURTHER INFORMATION CONTACT: Jiwan Karunatilake, Aerospace Engineer, Airframe and Propulsion Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7300; email *9-avs-nyaco-cos@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

The FAA invites you to send any written relevant data, views, or arguments about this proposal. Send your comments to an address listed under **ADDRESSES**. Include ''Docket No. FAA–2022–1566; Project Identifier MCAI–2022–00290–T'' at the beginning of your comments. The most helpful comments reference a specific portion of the proposal, explain the reason for any recommended change, and include supporting data. The FAA will consider all comments received by the closing date and may amend this proposal because of those comments.

Except for Confidential Business Information (CBI) as described in the following paragraph, and other information as described in 14 CFR 11.35, the FAA will post all comments received, without change, to *regulations.gov*, including any personal information you provide. The agency will also post a report summarizing each substantive verbal contact received about this NPRM.

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 NPRM 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 NPRM, it is important that you clearly designate the submitted comments as CBI. Please mark each page of your submission containing CBI as ''PROPIN.'' The FAA will treat such marked submissions as confidential under the FOIA, and they will not be placed in the public docket of this NPRM. Submissions containing CBI should be sent to Jiwan Karunatilake, Aerospace Engineer, Airframe and Propulsion Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7300; email *9-avs-nyaco-cos@faa.gov.* Any commentary that the FAA receives which is not specifically designated as CBI will be placed in the public docket for this rulemaking.

Background

Transport Canada, which is the aviation authority for Canada, has issued Transport Canada AD CF–2022–08, dated March 3, 2022 (Transport Canada AD CF–2022–08) (also referred to as the Mandatory Continuing Airworthiness Information, or the MCAI), to correct an unsafe condition for all Airbus Canada Limited Partnership (Type Certificate previously held by C Series Aircraft Limited Partnership (CSALP); Bombardier, Inc.) Model BD–500–1A10 and BD–500–1A11 airplanes. The MCAI states there have been several in-service findings of mechanical wear damage on the engine fuel feed system tubes and fuel tube connections on airplanes that are ''post-SB BD500–282004'' or that have the production equivalent. Transport Canada AD CF–2019–19R1, dated November 1, 2019 (Transport Canada AD CF–2019–19R1), among other actions, mandates modifying the fuel feed line installations in the fuel collector tanks using ACLP Service Bulletin BD500–282004, Issue 1, dated August 30, 2019. Transport Canada AD CF–2019–19R1 corresponds to FAA AD 2022–02–07, Amendment 39–21904 (87 FR 7027, February 8, 2022).

This proposed AD would require repetitive inspections of the fuel feed system for damage and replacement if necessary, as specified in Transport Canada AD CF–2022–08, which is proposed for incorporation by reference. The FAA is proposing this AD to address mechanical wear damage on the engine fuel feed system tubes and fuel tube connections. The unsafe condition, if not addressed, could result in failure of the affected fuel tubes and subsequent failure of the gravity transfer system, which could lead to a fuel imbalance resulting in a reduction in aircraft functional capabilities and increased crew workload. See the MCAI for additional background information.

You may examine the MCAI in the AD docket at *regulations.gov* under Docket No. FAA–2022–1566.

Related Service Information Under 1 CFR Part 51

Transport Canada AD CF–2022–08 specifies procedures for repetitive general visual inspections for mechanical wear damage (damage includes cracks, scores, scratches, nicks, and gouges) of the fuel feed system (the fuel feed tubes, related attaching hardware, and the area where the saddle clamp was installed), and rectification, such as replacement if any discrepancy is found after measuring any damage found during any inspection.

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**.

FAA's Determination

This product has been approved by the aviation authority of another country and is approved for operation in the United States. Pursuant to the FAA's bilateral agreement with the State of Design Authority, it has notified the FAA of the unsafe condition described in the MCAI described above. The FAA is issuing this NPRM after determining that the unsafe condition described previously is likely to exist or develop in other products of the same type design.

Proposed AD Requirements in This NPRM

This proposed AD would require accomplishing the actions specified in Transport Canada AD CF–2022–08 described previously, as incorporated by reference, except for any group identified as exceptions in the regulatory text of this proposed AD.

Explanation of Required Compliance Information

In the FAA's ongoing efforts to improve the efficiency of the AD process, the FAA developed a process to use some civil aviation authority (CAA) ADs as the primary source of information for compliance with requirements for corresponding FAA ADs. The FAA has been coordinating this process with manufacturers and CAAs. As a result, the FAA proposes to incorporate Transport Canada AD CF–2022–08 by reference in the FAA final rule. This proposed AD would, therefore, require compliance with Transport Canada AD CF–2022–08 in its entirety through that incorporation, except for any differences identified as exceptions in the regulatory text of this proposed AD. Service information required by Transport Canada AD CF–2022–08 for compliance will be available at *regulations.gov* under Docket No. FAA–2022–1566 after the FAA final rule is published.

Interim Action

The FAA considers that this proposed AD would be an interim action. This AD is considered interim action and further AD action may follow.

Costs of Compliance

The FAA estimates that this AD, if adopted as proposed, would affect 69 airplanes of U.S. registry. The FAA estimates the following costs to comply with this proposed AD:

ESTIMATED COSTS FOR REQUIRED ACTIONS

Labor cost	Parts cost	Cost per product	Cost on U.S. operators
74 work-hours × $85 per hour = $6,290	$0	$6,290	$434,010

ESTIMATED COSTS OF ON-CONDITION ACTIONS

Labor cost	Parts cost	Cost per product
7 work-hours × $85 per hour = $595	$57,284	Up to $57,879.

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

Authority for This Rulemaking

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

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

Regulatory Findings

The FAA determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would 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 this proposed regulation:

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

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

(3) Would 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 Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 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:

Airbus Canada Limited Partnership (Type Certificate Previously Held by C Series Aircraft Limited Partnership (CSALP); Bombardier, Inc.): Docket No. FAA–2022–1566; Project Identifier MCAI–2022–00290–T.

(a) Comments Due Date

The FAA must receive comments on this airworthiness directive (AD) by January 20, 2023.

(b) Affected ADs

None.

(c) Applicability

This AD applies to all Airbus Canada Limited Partnership (Type Certificate previously held by C Series Aircraft Limited Partnership (CSALP); Bombardier, Inc.) Model BD–500–1A10 and BD–500–1A11 airplanes, certificated in any category.

(d) Subject

Air Transport Association (ATA) of America Code 28, Fuel.

(e) Unsafe Condition

This AD was prompted by reports of mechanical wear damage on the engine fuel feed system tubes and fuel tube connections. The FAA is issuing this AD to address mechanical wear damage on the engine fuel feed system tubes and fuel tube connections. The unsafe condition, if not addressed, could result in failure of the affected fuel tubes and subsequent failure of the gravity transfer system, which could lead to a fuel imbalance resulting in a reduction in aircraft functional capabilities and increased crew workload.

(f) Compliance

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

(g) Requirements

Except as specified in paragraph (g) of this AD: Comply with all required actions and compliance times specified in, and in accordance with, Transport Canada AD CF–2022–08, dated March 3, 2022. (Transport Canada AD CF–2022–08).

(h) Exception to Transport Canada AD CF–2022–08

(1) Where Transport Canada AD CF–2022–08 refers to its effective date, this AD requires using the effective date of this AD.

(2) Where paragraph B. of Part 1 of Transport Canada AD CF–2022–08 specifies a compliance time for accomplishing the inspection, for this AD, the inspection must

be done at the time specified in paragraph (h)(2)(i) or (ii) of this AD, whichever occurs later.

(i) The compliance time specified in paragraph B. of Part 1 of Transport Canada AD CF–2022–08.

(ii) Within 60 flight hours or 7 days after the effective date of this AD, whichever occurs first.

(3) Where paragraph B. of part II of Transport Canada AD CF–2022–08 specifies a compliance time for accomplishing the inspection, for this AD, the inspection must be done at the time specified in paragraph (h)(3)(i) or (ii) of this AD, whichever occurs later.

(i) The compliance time specified in paragraph B. of Part II of Transport Canada AD CF–2022–08.

(ii) Within 60 flight hours or 7 days after the effective date of this AD, whichever occurs first.

(4) Where Transport Canada AD CF–2022–08 refers to hour's air time, this AD requires using flight hours.

(5) Where Transport Canada AD CF–2022–08 specifies to ''rectify any discrepancy'' for this AD, replace the text ''rectify any discrepancy'' with ''if any mechanical wear damage is found on which the measured damage is within the specifications identified in ACLP SB BD500–282006, before further flight replace the affected part.''

(i) No Reporting Requirement

Although the service information referenced in Transport Canada AD CF–2022–08 specifies to submit certain information to the manufacturer, this AD does not include that requirement.

(j) Additional AD Provisions

The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, New York ACO Branch, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or responsible Flight Standards Office, as appropriate. If sending information directly to the manager of the certification office, send it to the attention of the person identified in paragraph (k) of this AD. Information may be emailed to: *9-AVS-AIR-730-AMOC@faa.gov* ATTN: Program Manager, Continuing Operational Safety, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7300. Before using any approved AMOC, notify your appropriate principal inspector, or lacking a principal inspector, the manager of the responsible Flight Standards Office.

(2) *Contacting the Manufacturer:* For any requirement in this AD to obtain instructions from a manufacturer, the instructions must be accomplished using a method approved by the Manager, New York ACO Branch, FAA; or Transport Canada; or Airbus Canada Limited Partnership (Type Certificate Previously Held by C Series Aircraft Limited Partnership (CSALP); Bombardier, Inc.) Transport Canada Design Approval Organization (DAO). If approved by the DAO, the approval must include the DAO-authorized signature.

(3) *Required for Compliance (RC):* Except as required by paragraphs (i) and (j)(2) of this AD, if any service information contains procedures or tests that are identified as RC, those procedures and tests must be done to comply with this AD; any procedures or tests that are not identified as RC are recommended. Those procedures and tests that are not identified as RC may be deviated from using accepted methods in accordance with the operator's maintenance or inspection program without obtaining approval of an AMOC, provided the procedures and tests identified as RC can be done and the airplane can be put back in an airworthy condition. Any substitutions or changes to procedures or tests identified as RC require approval of an AMOC.

(k) Additional Information

For more information about this AD, contact Jiwan Karunatilake, Aerospace Engineer, Airframe and Propulsion Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7300; email *9-avs-nyaco-cos@faa.gov.*

(l) Material Incorporated by Reference

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

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

(i) Transport Canada AD CF–2022–08, dated March 3, 2022.

(ii) [Reserved]

(3) For Transport Canada AD CF–2022–08, contact Transport Canada, Transport Canada National Aircraft Certification, 159 Cleopatra Drive, Nepean, Ontario K1A 0N5, Canada; telephone 888–663–3639; email *AD-CN@tc.gc.ca;* website *tc.canada.ca/en/aviation.*

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

(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 November 29, 2022.

Christina Underwood,

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

[FR Doc. 2022–26410 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2022–1573; Project Identifier MCAI–2022–00671–T]

RIN 2120–AA64

Airworthiness Directives; Airbus SAS Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to supersede Airworthiness Directive (AD) 2020–22–16, AD 2021–16–01, and AD 2022–04–03, which apply to certain Airbus SAS Model A318, A320 and A321 series airplanes; and Model A319–111, –112, –113, –114, –115, –131, –132, –133, –151N, and –153N airplanes. AD 2020–22–16, AD 2021–16–01, and AD 2022–04–03 require revising the existing maintenance or inspection program, as applicable, to incorporate new or more restrictive airworthiness limitations. Since the FAA issued AD 2020–22–16, AD 2021–16–01, and AD 2022–04–03, the FAA has determined that new or more restrictive airworthiness limitations are necessary. This proposed AD would continue to require the actions in AD 2020–22–16, AD 2021–16–01, and AD 2022–04–03, and would require revising the existing maintenance or inspection program, as applicable, to incorporate additional new or more restrictive airworthiness limitations, as specified in a European Union Aviation Safety Agency (EASA) AD, which is proposed for incorporation by reference (IBR). The FAA is proposing this AD to address the unsafe condition on these products.

DATES: The FAA must receive comments on this proposed AD by January 20, 2023.

ADDRESSES: You may send comments, using the procedures found in 14 CFR 11.43 and 11.45, by any of the following methods:

- *Federal eRulemaking Portal:* Go to *regulations.gov*. Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

AD Docket: You may examine the AD docket at *regulations.gov* under Docket No. FAA–2022–1573; 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 NPRM, the mandatory continuing airworthiness information (MCAI), any comments received, and other information. The street address for Docket Operations is listed above.

Material Incorporated by Reference:

• For the EASA ADs identified in this NPRM, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; telephone +49 221 8999 000; email *ADs@easa.europa.eu;* website *easa.europa.eu*. You may find this material on the EASA website at *ad.easa.europa.eu*. It is also available in the AD docket at *regulations.gov* under Docket No. FAA–2022–1573 may view this material at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195.

FOR FURTHER INFORMATION CONTACT:
Hyeyoon Jang, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th St., Des Moines, WA 98198; telephone 817–222–5584; email *hye.yoon.jang@faa.gov*.

SUPPLEMENTARY INFORMATION:

Comments Invited

The FAA invites you to send any written relevant data, views, or arguments about this proposal. Send your comments to an address listed under **ADDRESSES**. Include ''Docket No. FAA–2022–1573; Project Identifier MCAI–2022–00671–T'' at the beginning of your comments. The most helpful comments reference a specific portion of the proposal, explain the reason for any recommended change, and include supporting data. The FAA will consider all comments received by the closing date and may amend this proposal because of those comments.

Except for Confidential Business Information (CBI) as described in the following paragraph, and other information as described in 14 CFR 11.35, the FAA will post all comments received, without change, to *regulations.gov,* including any personal information you provide. The agency will also post a report summarizing each substantive verbal contact received about this NPRM.

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 NPRM 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 NPRM, it is important that you clearly designate the submitted comments as CBI. Please mark each page of your submission containing CBI as ''PROPIN.'' The FAA will treat such marked submissions as confidential under the FOIA, and they will not be placed in the public docket of this NPRM. Submissions containing CBI should be sent to Hyeyoon Jang, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th St., Des Moines, WA 98198; telephone 817–222–5584; email *hye.yoon.jang@faa.gov*. Any commentary that the FAA receives which is not specifically designated as CBI will be placed in the public docket for this rulemaking.

Background

The FAA issued AD 2020–22–16, Amendment 39–21312 (85 FR 70439, November 5, 2020) (AD 2020–22–16) for certain Airbus SAS Model A318 series airplanes; Model A319–111, –112, –113, –114, –115, –131, –132, –133, –151N, and –153N airplanes; Model A320 series airplanes; and Model A321 series airplanes. AD 2020–22–16 was prompted by an MCAI originated by EASA, which is the Technical Agent for the Member States of the European Union. EASA issued AD 2020–0067, dated March 23, 2020 (EASA AD 2020–0067) (which corresponds to FAA AD 2020–22–16) to correct an unsafe condition. AD 2020–22–16 requires revising the existing maintenance or inspection program, as applicable, to incorporate new or more restrictive airworthiness limitations. The FAA issued AD 2020–22–16 to address a safety-significant latent failure (that is not annunciated), which, in combination with one or more other specific failures or events, could result in a hazardous or catastrophic failure condition.

The FAA issued AD 2021–16–01, Amendment 39–21662 (86 FR 47212, August 24, 2021) (AD 2021–16–01), for certain Airbus SAS Model A318 series airplanes; Model A319–111, –112, –113, –114, –115, –131, –132, –133, –151N, and –153N airplanes; Model A320 series airplanes; and Model A321 series airplanes. AD 2021–16–01 was prompted by EASA AD 2020–0219, dated October 12, 2020 (EASA AD 2020–0219) (which corresponds to FAA AD 2021–16–01) to correct an unsafe condition. AD 2021–16–01 requires revising the existing maintenance or inspection program, as applicable, to incorporate new or more restrictive airworthiness limitations. The FAA issued AD 2021–16–01 to address safety-significant latent failure (that is not annunciated), which, in combination with one or more other specific failures or events, could result in a hazardous or catastrophic failure condition. AD 2021–16–01 specifies that accomplishing the revision required by that AD terminates the corresponding requirements of AD 2020–22–16, for the tasks identified in the service information referred to in EASA AD 2020–0219, dated October 12, 2020, only.

The FAA issued AD 2022–04–03, Amendment 39–21944 (87 FR 10064, February 23, 2022) (AD 2022–04–03), for certain Airbus SAS Model A318 series airplanes; Model A319–111, –112, –113, –114, –115, –131, –132, –133, –151N, and –153N airplanes; and Model A320 and A321 series airplanes. AD 2022–04–03 was prompted by EASA AD 2021–0108, dated April 20, 2021 (EASA AD 2021–0108) (which corresponds to FAA AD 2022–04–03). AD 2022–04–03 requires revising the existing maintenance or inspection program, as applicable, to incorporate new or more restrictive airworthiness limitations. The FAA issued AD 2022–04–03 to address a safety-significant latent failure (that is not annunciated), which, in combination with one or more other specific failures or events, could result in a hazardous or catastrophic failure condition. AD 2022–04–03 specifies that accomplishing the revision required by that AD terminates the limitations of Task 262300–00001–1–C, as required by paragraph (i) of AD 2020–22–16, for airplanes with an original airworthiness certificate or original export certificate of airworthiness issued on or before January 17, 2020 only.

Actions Since AD 2020–22–16, AD 2021–16–01, and AD 2022–04–03 Were Issued

Since the FAA issued AD 2020–22–16, AD 2021–16–01, and AD 2022–04–03, EASA superseded ADs 2020–0067, 2020–0219, and 2021–0108; and issued EASA AD 2022–0091, dated May 20, 2022 (EASA AD 2022–0091) (also referred to as the MCAI), for certain Model A318 series, A319 series, A321 series, and Model A320–211, –212, –214, –215, –216, –231, –232, –233, –251N, –252N, –253N, –271N, –272N, and –273N airplanes. Model A320–215 airplanes are not certificated by the FAA and are not included on the U.S. type certificate data sheet; this proposed AD therefore does not include those airplanes in the applicability.

Airplanes with an original airworthiness certificate or original export certificate of airworthiness issued after February 18, 2022 must comply with the airworthiness limitations specified as part of the approved type design and referenced on the type certificate data sheet; this AD therefore does not include those airplanes in the applicability.

The FAA is proposing this AD to address a safety-significant latent failure (that is not annunciated), which, in combination with one or more other specific failures or events, could result in a hazardous or catastrophic failure condition. You may examine the MCAI in the AD docket at regulations.gov under Docket No. FAA–2022–1573.

Related Service Information Under 1 CFR Part 51

EASA AD 2022–0091 specifies new or more restrictive airworthiness limitations for certification maintenance requirements.

This proposed AD would also require EASA AD 2020–0067, dated March 23, 2020; which the Director of the Federal Register approved for incorporation by reference as of December 10, 2020 (85 FR 70439, November 5, 2020).

This proposed AD would also require EASA AD 2020–0219, dated October 12, 2020, which the Director of the Federal Register approved for incorporation by reference as of September 28, 2021 (86 FR 47212, August 24, 2021).

This proposed AD would also require EASA AD 2021–0108, dated April 20, 2021, which the Director of the Federal Register approved for incorporation by reference as of March 30, 2022 (87 FR 10064, February 23, 2022).

This material is reasonably available because the interested parties have access to it through their normal course of business or by the means identified in the **ADDRESSES** section.

FAA's Determination

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 the State of Design Authority, it has notified the FAA of the unsafe condition described in the MCAI described above. The FAA is issuing this NPRM after determining that the unsafe condition described previously is likely to exist or develop in other products of these same type designs.

Proposed AD Requirements in This NPRM

This proposed AD would retain the requirements of AD 2020–22–16, AD 2021–16–01, and AD 2022–04–03. This proposed AD would also require revising the existing maintenance or inspection program, as applicable, to incorporate additional new or more restrictive airworthiness limitations, which are specified in EASA AD 2022–0091 described previously, as proposed for incorporation by reference. Any differences with EASA AD 2022–0091 are identified as exceptions in the regulatory text of this AD.

This proposed AD would require revisions to certain operator maintenance documents to include new actions (*e.g.,* inspections). Compliance with these actions is required by 14 CFR 91.403(c). For airplanes that have been previously modified, altered, or repaired in the areas addressed by this proposed AD, the operator may not be able to accomplish the actions described in the revisions. In this situation, to comply with 14 CFR 91.403(c), the operator must request approval for an alternative method of compliance (AMOC) according to paragraph (s)(1) of this proposed AD.

Explanation of Required Compliance Information

In the FAA's ongoing efforts to improve the efficiency of the AD process, the FAA developed a process to use some civil aviation authority (CAA) ADs as the primary source of information for compliance with requirements for corresponding FAA ADs. The FAA has been coordinating this process with manufacturers and CAAs. As a result, the FAA proposes to retain the IBR of EASA ADs 2020–0067, 2020–0219, and 2021–0108, and incorporate EASA AD 2022–0091 by reference in the FAA final rule. This proposed AD would, therefore, require compliance with EASA ADs 2022–0091, 2020–0067, 2020–0219, and 2021–0108 through that incorporation, except for any differences identified as exceptions in the regulatory text of this proposed AD. Using common terms that are the same as the heading of a particular section in EASA ADs 2022–0091, 2020–0067, 2020–0219, or 2021–0108 does not mean that operators need comply only with that section. For example, where the AD requirement refers to "all required actions and compliance times," compliance with this AD requirement is not limited to the section titled "Required Action(s) and Compliance Time(s)" in EASA ADs 2022–0091, 2020–0067, 2020–0219, or 2021–0108. Service information required by EASA ADs 2022–0091, 2020–0067, 2020–0219, and 2021–0108 for compliance will be available at *regulations.gov* under Docket No. FAA–2022–1573 after the FAA final rule is published.

Airworthiness Limitation ADs Using the New Process

The FAA's process of incorporating by reference MCAI ADs as the primary source of information for compliance with corresponding FAA ADs has been limited to certain MCAI ADs (primarily those with service bulletins as the primary source of information for accomplishing the actions required by the FAA AD). However, the FAA is now expanding the process to include MCAI ADs that require a change to airworthiness limitation documents, such as airworthiness limitation sections.

For these ADs that incorporate by reference an MCAI AD that changes airworthiness limitations, the FAA requirements are unchanged. Operators must revise the existing maintenance or inspection program, as applicable, to incorporate the information specified in the new airworthiness limitation document. The airworthiness limitations must be followed according to 14 CFR 91.403(c) and 91.409(e).

The previous format of the airworthiness limitation ADs included a paragraph that specified that no alternative actions (*e.g.,* inspections) may be used unless the actions and intervals are approved as an AMOC in accordance with the procedures specified in the AMOCs paragraph under "Additional AD Provisions." This new format includes a "New Provisions for Alternative Actions and Intervals" paragraph that does not specifically refer to AMOCs, but operators may still request an AMOC to use an alternative action or interval.

Costs of Compliance

The FAA estimates that this proposed AD affects 1,680 airplanes of U.S. registry. The FAA estimates the following costs to comply with this proposed AD:

The FAA estimates the total cost per operator for the retained actions from AD 2020–22–16, AD 2021–16–01, and AD 2022–04–03 to be $7,650 (90 work-hours × $85 per work-hour) per AD.

The FAA has determined that revising the existing maintenance or inspection program takes an average of 90 work-hours per operator, although the agency recognizes that this number may vary from operator to operator. Since operators incorporate maintenance or inspection program changes for their affected fleet(s), the FAA has determined that a per-operator estimate is more accurate than a per-airplane estimate.

The FAA estimates the total cost per operator for the new proposed actions to be $7,650 (90 work-hours × $85 per work-hour).

Authority for This Rulemaking

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

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

Regulatory Findings

The FAA determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would 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 this proposed regulation:

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

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

(3) Would 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 Proposed Amendment

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

PART 39—AIRWORTHINESS DIRECTIVES

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

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

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by:

■ a. Removing Airworthiness Directives (AD) 2020–22–16, Amendment 39–21312 (85 FR 70439, November 5, 2020); AD 2021–16–01, Amendment 39–21662 (86 FR 47212, August 24, 2021); and AD 2022–04–03, Amendment 39–21944 (87 FR 10064, February 23, 2022).

■ b. Adding the following new AD:

Airbus SAS: Docket No. FAA–2022–1573; Project Identifier MCAI–2022–00671–T.

(a) Comments Due Date

The FAA must receive comments on this airworthiness directive (AD) by January 20, 2023.

(b) Affected ADs

This AD replaces the ADs specified in paragraphs (c)(1) through (3) of this AD.

(1) AD 2020–22–16, Amendment 39–21312 (85 FR 70439, November 5, 2020) (AD 2020–22–16).

(2) AD 2021–16–01, Amendment 39–21662 (86 FR 47212, August 24, 2021) (AD 2021–16–01).

(3) AD 2022–04–03, Amendment 39–21944 (87 FR 10064, February 23, 2022) (AD 2022–04–03).

(c) Applicability

This AD applies to the Airbus SAS airplanes specified in paragraphs (c)(1) through (4) of this AD, certificated in any category, with an original airworthiness certificate or original export certificate of airworthiness issued on or before February 18, 2022.

(1) Model A318–111, –112, –121, and –122 airplanes.

(2) Model A319–111, –112, –113, –114, –115, –131, –132, –133, –151N, –153N, and –171N airplanes.

(3) Model A320–211, –212, –214, –216, –231, –232, –233, –251N, –252N, –253N, –271N, –272N, and –273N airplanes.

(4) Model A321–111, –112, –131, –211, –212, –213, –231, –232, –251N, –252N, –253N, –271N, –272N, –251NX, –252NX, –253NX, –271NX, and –272NX airplanes.

(d) Subject

Air Transport Association (ATA) of America Code 05, Time Limits/Maintenance Checks.

(e) Unsafe Condition

This AD was prompted by a determination that new or more restrictive airworthiness limitations are necessary. The FAA is issuing this AD to address to address a safety significant latent failure (that is not annunciated), which, in combination with one or more other specific failures or events, could result in a hazardous or catastrophic failure condition.

(f) Compliance

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

(g) Retained Revision of the Existing Maintenance or Inspection Program From AD 2020–22–16, With No Changes

This paragraph restates the requirements of paragraph (i) of AD 2020–22–16, with no changes. For airplanes with an original airworthiness certificate or original export certificate of airworthiness issued on or before January 17, 2020, except for Model A319–171N airplanes: Except as specified in paragraph (h) of this AD: Comply with all required actions and compliance times specified in, and in accordance with, European Union Aviation Safety Agency (EASA) AD 2020–0067, dated March 23, 2020 (EASA AD 2020–0067). Accomplishing the revision of the existing maintenance or inspection program required by paragraph (o) of this AD terminates the requirements of this paragraph.

(h) Retained Exceptions to EASA AD 2020–0067 With No Changes

This paragraph restates the exceptions specified in paragraph (j) of AD 2020–22–16, with no changes.

(1) The requirements specified in paragraphs (1) and (2) of EASA AD 2020–0067 do not apply to this AD.

(2) Paragraph (3) of EASA AD 2020–0067 specifies revising ''the AMP'' within 12 months after its effective date, but this AD requires revising the existing maintenance or inspection program, as applicable, to incorporate the ''tasks and associated thresholds and intervals'' specified in paragraph (3) of EASA AD 2020–0067 within 90 days after December 10, 2020 (the effective date of AD 2020–22–16).

(3) The initial compliance time for doing the tasks specified in paragraph (3) of EASA AD 2020–0067 is at the applicable ''associated thresholds'' specified in paragraph (3) of EASA AD 2020–0067, or within 90 days after December 10, 2020 (the effective date of AD 2020–22–16), whichever occurs later.

(4) The provisions specified in paragraphs (4) and (5) of EASA AD 2020–0067 do not apply to this AD.

(5) The ''Remarks'' section of EASA AD 2020–0067 does not apply to this AD.

(i) Retained Restrictions on Alternative Actions and Intervals From AD 2020–22–16, With a New Exception

This paragraph restates the requirements of paragraph (k) of AD 2020–22–16, with a new exception. Except as required by paragraph (o) of this AD, after the maintenance or inspection program has been revised as required by paragraph (g) of this AD, no alternative actions (*e.g.,* inspections) or intervals are allowed unless they are approved as specified in the provisions of the ''Ref. Publications'' section of EASA AD 2020–0067.

(j) Retained Revision of the Existing Maintenance or Inspection Program From AD 2021–16–01 With No Changes

This paragraph restates the requirements of paragraph (g) of AD 2021–16–01, with no changes. For airplanes with an original airworthiness certificate or original export certificate of airworthiness issued on or before June 10, 2020, except for Model A319–171N airplanes: Revise the existing maintenance or inspection program, as applicable, by incorporating task(s) and associated thresholds and intervals specified in paragraph (3) of EASA AD 2020–0219, dated October 12, 2020 (EASA AD 2020–0219), except you are required to incorporate task(s) and associated thresholds and intervals within 90 days after September 28, 2021 (the effective date of AD 2021–16–01). Record a compliance time for the initial tasks of either the applicable ''thresholds'' incorporated by the requirements of paragraph (3) of EASA AD 2020–0219 or 90 days after September 28, 2021 (the effective date of AD 2021–16–01), whichever would occur later. Accomplishing the revision of the existing maintenance or inspection program required by paragraph (o) of this AD terminates the requirements of this paragraph.

(k) Retained Restrictions on Alternative Actions and Intervals From AD 2021–16–01, With a New Exception

This paragraph restates the requirements of paragraph (h) of AD 2021–16–01, with a new exception. Except as required by paragraph (o) of this AD, after the existing maintenance or inspection program has been revised as required by paragraph (j) of this AD, no alternative actions (*e.g.,* inspections) and intervals are allowed unless they are approved as specified in the provisions of the ''Ref. Publications'' section of EASA AD 2020–0219.

(l) Retained Revision of the Existing Maintenance or Inspection Program From AD 2022–04–03, With No Changes

This paragraph restates the requirements of paragraph (g) of AD 2022–04–03, with no changes. For airplanes with an original airworthiness certificate or original export certificate of airworthiness issued on or before December 9, 2020, except for Model A319–171N airplanes: Except as specified in paragraph (m) of this AD: Comply with all required actions and compliance times specified in, and in accordance with, EASA AD 2021–0108, dated April 20, 2021 (EASA AD 2021–0108). Accomplishing the revision of the existing maintenance or inspection program required by paragraph (o) of this AD terminates the requirements of this paragraph.

(m) Retained Exceptions to EASA AD 2021–0108, With No Changes

This paragraph restates the exceptions specified in paragraph (h) of AD 2022–04–03, with no changes.

(1) Where EASA AD 2021–0108 refers to its effective date, this AD requires using March 30, 2022 (the effective date of AD 2022–04–03).

(2) The requirements specified in paragraphs (1) and (2) of EASA AD 2021–0108 do not apply to this AD.

(3) Paragraph (3) of EASA AD 2021–0108 specifies revising ''the approved AMP'' within 12 months after its effective date, but this AD requires revising the existing maintenance or inspection program, as applicable, within 90 days after March 30, 2022 (the effective date of AD 2022–04–03).

(4) The initial compliance time for doing the tasks specified in paragraph (3) of EASA 2021–0108 is at the applicable ''thresholds'' as incorporated by the requirements of paragraph (3) of EASA AD 2021–0108, or within 90 days after March 30, 2022 (the effective date of AD 2022–04–03), whichever occurs later.

(5) The provisions specified in paragraphs (4) of EASA AD 2021–0108 do not apply to this AD.

(6) The ''Remarks'' section of EASA AD 2021–0108 does not apply to this AD.

(n) Retained Restrictions on Alternative Actions and Intervals From AD 2022–04–03, With a New Exception

This paragraph restates the requirements of paragraph (i) of AD 2022–04–03, with a new exception. Except as required by paragraph (o) of this AD, after the existing maintenance or inspection program has been revised as required by paragraph (l) of this AD, no alternative actions (*e.g.,* inspections) and intervals are allowed unless they are approved as specified in the provisions of the ''Ref. Publications'' section of EASA AD 2021–0108.

(o) New Revision of the Existing Maintenance or Inspection Program

Except as specified in paragraph (p) of this AD: Comply with all required actions and compliance times specified in, and in accordance with EASA AD 2022–0091, dated May 20, 2022 (EASA AD 2022–0091). Accomplishing the revision of the existing maintenance or inspection program required by this paragraph terminates the requirements of paragraphs (g) (j), and (l) of this AD.

(p) Exceptions to EASA AD 2022–0091

(1) The requirements specified in paragraphs (1) and (2) of EASA AD 2022–0091 do not apply to this AD.

(2) Paragraph (3) of EASA AD 2022–0091 specifies revising ''the approved AMP'' within 12 months after its effective date, but this AD requires revising the existing maintenance or inspection program, as applicable, within 90 days after the effective date of this AD.

(3) The initial compliance time for doing the tasks specified in paragraph (3) of EASA AD 2022–0091 is at the applicable ''associated thresholds'' as incorporated by the requirements of paragraph (3) of EASA AD 2022–0091, or within 90 days after the effective date of this AD, whichever occurs later.

(4) The provisions specified in paragraphs (4) and (5) of EASA AD 2022–0091 do not apply to this AD.

(5) The ''Remarks'' section of EASA AD 2022–0091 does not apply to this AD.

(q) Provisions for Alternative Actions and Intervals

After the existing maintenance or inspection program has been revised as required by paragraph (o) of this AD, no alternative actions (*e.g.,* inspections) and intervals are allowed unless they are approved as specified in the provisions of the ''Ref. Publications'' section of EASA AD 2022–0091.

(r) Terminating Action for Certain Requirements of AD 2020–22–16

(1) Accomplishing the actions required by paragraph (j) of this AD terminates the corresponding requirements of AD 2020–22–16, for the tasks identified in the service information referred to in EASA AD 2020–0219 only.

(2) Accomplishing the actions required by paragraph (l) of this AD terminates the limitations of Task 262300–00001–1–C, as required by paragraph (i) of AD 2020–22–16, for airplanes with an original airworthiness certificate or original export certificate of airworthiness issued on or before January 17, 2020 only.

(s) Additional AD Provisions

The following provisions also apply to this AD:

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

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

(t) Additional Information

For more information about this AD, contact Hyeyoon Jang, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th St., Des Moines, WA 98198; telephone 817–222–5584; email *hye.yoon.jang@faa.gov.*

(u) Material Incorporated by Reference

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

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

(3) The following service information was approved for IBR on [DATE 35 DAYS AFTER PUBLICATION OF THE FINAL RULE].

(i) European Union Aviation Safety Agency (EASA) AD 2022–0091, dated May 20, 2022.

(ii) [Reserved]

(4) The following service information was approved for IBR on December 10, 2020 (85 FR 70439, November 5, 2020).

(i) European Union Aviation Safety Agency (EASA) AD 2020–0067, dated March 23, 2020.

(ii) [Reserved]

(5) The following service information was approved for IBR on September 28, 2021 (86 FR 47212, August 24, 2021).

(i) European Union Aviation Safety Agency (EASA) AD 2020–0219, dated October 12, 2020.

(ii) [Reserved]

(6) The following service information was approved for IBR on March 30, 2022 (87 FR 10064, February 23, 2022).

(i) European Union Aviation Safety Agency (EASA) AD 2021–0108, dated April 20, 2021.

(ii) [Reserved]

(7) For EASA ADs 2022–0091, 2020–0067, 2020–0219, and 2021–0108, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; telephone +49 221 8999 000; email *ADs@easa.europa.eu;* website *easa.europa.eu.* You may find these EASA ADs on the EASA website at *ad.easa.europa.eu.*

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

(9) 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 December 1, 2022.

Christina Underwood,

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

[FR Doc. 2022–26472 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2022–1572; Project Identifier MCAI–2022–00350–T]

RIN 2120–AA64

Airworthiness Directives; Bombardier, Inc. Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to adopt a new airworthiness directive (AD) for all Bombardier, Inc., Model CL–600–1A11 (600), CL–600–2A12 (601), and CL–600–2B16 (601–3A, 601–3R, and 604 Variants) airplanes. This proposed AD was prompted by a determination that, due to a lack of flightcrew awareness, smoke hoods with a certain part number installed throughout the airplane could be mistaken for protective breathing equipment (PBE). This proposed AD would require an inspection or records review to determine if any smoke hood with a certain part number is installed in any location on the airplane and, depending on the results, removing the smoke hood and associated placards and installing new placards. The FAA is proposing this AD to address the unsafe condition on these products.

DATES: The FAA must receive comments on this proposed AD by January 20, 2023.

ADDRESSES: You may send comments, using the procedures found in 14 CFR 11.43 and 11.45, by any of the following methods:

- *Federal eRulemaking Portal:* Go to *regulations.gov*. Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

AD Docket: You may examine the AD docket at *regulations.gov* under Docket No. FAA–2022–1572; 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 NPRM, the mandatory continuing airworthiness information (MCAI), any comments received, and other information. The street address for Docket Operations is listed above.

Material Incorporated by Reference:

- For service information identified in this NPRM, contact Bombardier Business Aircraft Customer Response Center, 400 Côte-Vertu Road West, Dorval, Québec H4S 1Y9, Canada; telephone 514–855–2999; email *ac.yul@aero.bombardier.com*; website: *bombardier.com*.
- You may view this service information at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195.

FOR FURTHER INFORMATION CONTACT: Chirayu Gupta, Aerospace Engineer, Mechanical Systems and Administrative Services Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7300; email *9-avs-nyaco-cos@faa.gov*.

SUPPLEMENTARY INFORMATION:

Comments Invited

The FAA invites you to send any written relevant data, views, or arguments about this proposal. Send your comments to an address listed under **ADDRESSES**. Include ''Docket No. FAA–2022–1572; Project Identifier MCAI–2022–00350–T'' at the beginning of your comments. The most helpful comments reference a specific portion of the proposal, explain the reason for any recommended change, and include supporting data. The FAA will consider all comments received by the closing date and may amend the proposal because of those comments.

Except for Confidential Business Information (CBI) as described in the following paragraph, and other information as described in 14 CFR 11.35, the FAA will post all comments received, without change, to *regulations.gov,* including any personal information you provide. The agency will also post a report summarizing each substantive verbal contact received about this NPRM.

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 NPRM 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 NPRM, it is important that you clearly designate the submitted comments as CBI. Please mark each page of your submission containing CBI as ''PROPIN.'' The FAA will treat such marked submissions as confidential under the FOIA, and they will not be placed in the public docket of this NPRM. Submissions containing CBI should be sent to Chirayu Gupta, Aerospace Engineer, Mechanical Systems and Administrative Services Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7300; email *9-avs-nyaco-cos@faa.gov*. Any commentary that the FAA receives which is not specifically designated as CBI will be placed in the public docket for this rulemaking.

Background

Transport Canada, which is the aviation authority for Canada, has issued Transport Canada AD CF–2022–10, dated March 10, 2022 (Transport Canada AD CF–2022–10) (also referred to after this as the MCAI), to correct an unsafe condition on all Bombardier, Inc. Model CL–600–1A11, CL–600–2A12, and CL–600–2B16 airplanes. The MCAI states that Bombardier, Inc., determined that, due to a lack of flightcrew awareness, smoke hoods with a certain part number installed throughout the airplane could be mistaken for PBE. The MCAI requires that operators verify if a smoke hood with a certain part number is installed in any location on the airplane and, depending on the results, removing the smoke hood and associated placards and installing new placards. The MCAI states that in a fire or smoke event the flightcrew might initially attempt to use the smoke hood believing it to be PBE, which could result in a delay in identifying the source of the smoke or fire.

You may examine the MCAI in the AD docket at *regulations.gov* under Docket No. FAA–2022–1572.

Related Service Information Under 1 CFR Part 51

The FAA reviewed the following Bombardier, Inc. service information, which specify procedures to verify (via inspection or records review) if any smoke hood having part number MR–10008N is installed in the flight deck, forward wardrobe or any location on the airplane, removing any affected smoke hood and associated placards, and installing new placards. These documents are distinct since they apply to different airplane models and configurations.

- Bombardier Service Bulletin 600–0778, dated September 22, 2021.
- Bombardier Service Bulletin 601–1110, dated September 22, 2021.
- Bombardier Service Bulletin 604–25–004, dated September 22, 2021.
- Bombardier Service Bulletin, 605–25–014, dated September 22, 2021.
- Bombardier Service Bulletin, 650–25–016, dated September 22, 2021.

This service information is reasonably available because the interested parties have access to it through their normal course of business or by the means identified in the **ADDRESSES** section.

FAA's Determination

This product has been approved by the aviation authority of another country, and is approved for operation in the United States. Pursuant to the FAA's bilateral agreement with this State of Design Authority, it has notified the FAA of the unsafe condition described in the MCAI and service information described above. The FAA is issuing this NPRM after determining that the unsafe condition described previously is likely to exist or develop on other products of the same type design.

Proposed AD Requirements in This NPRM

This proposed AD would require accomplishing the actions specified in the service information already described.

Costs of Compliance

The FAA estimates that this AD, if adopted as proposed, would affect 698 airplanes of U.S. registry. The FAA estimates the following costs to comply with this proposed AD:

ESTIMATED COSTS FOR REQUIRED ACTIONS

Labor cost	Parts cost	Cost per product	Cost on U.S. operators
1 work-hour × $85 per hour = $85	$0	$85	$59,330

The FAA estimates the following costs to do any necessary on-condition actions that would be required based on the results of any required actions. The FAA has no way of determining the number of aircraft that might need these on-condition actions:

ESTIMATED COSTS OF ON-CONDITION ACTIONS

Labor cost	Parts cost	Cost per product
1 work-hour × $85 per hour = $85	$9	$94

Authority for This Rulemaking

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

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

Regulatory Findings

The FAA determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would 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 this proposed regulation:

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

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

(3) Would 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 Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 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:

Bombardier, Inc.: Docket No. FAA–2022–1572; Project Identifier MCAI–2022–00350–T.

(a) Comments Due Date

The FAA must receive comments on this airworthiness directive (AD) by January 20, 2023.

(b) Affected ADs

None.

(c) Applicability

This AD applies to all Bombardier, Inc., airplanes, certificated in any category, as identified in paragraphs (c)(1) through (3) of this AD.

(1) Model CL–600–1A11 (600) airplanes.

(2) Model CL–600–2A12 (601) airplanes.

(3) Model CL–600–2B16 (601–3A, 601–3R, and 604 Variants) airplanes.

(d) Subject

Air Transport Association (ATA) of America Code 25, Equipment/furnishings.

(e) Unsafe Condition

This AD was prompted by a determination that, due to a lack of flightcrew awareness, smoke hoods with a certain part number installed throughout the airplane could be mistaken for protective breathing equipment (PBE). The FAA is issuing this AD to address, in a fire or smoke event, that the flightcrew might initially attempting to use the smoke hood believing it to be PBE. The unsafe condition, if not addressed, could result in a delay in identifying the source of the smoke or fire.

(f) Compliance

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

(g) Inspection

Within 12 months after the effective date of this AD: Do an inspection to determine if any smoke hood having part number (P/N) MR–10008N is installed in the flight deck, forward wardrobe, or any other location in the airplane. A review of airplane maintenance records is acceptable in lieu of this inspection if the part number of the smoke hood can be conclusively determined from that review.

(h) Corrective Action

If, during the inspection or records review required by paragraph (g) of this AD, any smoke hood having P/N MR–10008N is found on the airplane, within 12 months after the effective date of this AD, remove the smoke hood, including any associated placards, and install a new placard, in accordance with Section 2.B. of the Accomplishment Instructions of the applicable Bombardier service bulletin specified in paragraphs (h)(1) through (5) of this AD; or the method specified in paragraph (h)(6) of this AD; as applicable.

(1) For Model CL–600–1A11 (600) airplanes: Bombardier Service Bulletin 600–0778, dated September 22, 2021.

(2) For Model CL–600–2A12 (601) airplanes: Bombardier Service Bulletin 601–1110, dated September 22, 2021.

(3) For Model CL–600–2B16 airplanes (604 variant) with serial numbers 5301 through 5644 inclusive: Bombardier Service Bulletin 604–25–004, dated September 22, 2021.

(4) For Model CL–600–2B16 (604 variant) airplanes with serial numbers 5701 through 5988 inclusive: Bombardier Service Bulletin 605–25–014, dated September 22, 2021.

(5) For Model CL–600–2B16 airplanes (604 variant) with serial numbers 6050 through 6099 inclusive: Bombardier Service Bulletin 650–25–016, dated September 22, 2021.

(6) For Model CL–600–2B16 (601–3A and 601–3R Variants) airplanes: A method approved by the Manager, New York ACO Branch, FAA; or Transport Canada; or Bombardier, Inc.'s Transport Canada Design Approval Organization (DAO). If approved by the DAO, the approval must include the DAO-authorized signature.

(i) Additional AD Provisions

The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, New York ACO Branch, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. In accordance with 14 CFR 39.19, send your request to your principal inspector or responsible Flight Standards Office, as appropriate. If sending information directly to the manager of the New York ACO Branch, mail it to ATTN: Program Manager, Continuing Operational Safety, at the address identified in paragraph (j)(2) of this AD or email to: *9-avs-nyaco-cos@faa.gov*. If mailing information, also submit information by email. Before using any approved AMOC, notify your appropriate principal inspector, or lacking a principal inspector, the manager of the responsible Flight Standards Office.

(2) *Contacting the Manufacturer:* For any requirement in this AD to obtain instructions from a manufacturer, the instructions must be accomplished using a method approved by the Manager, New York ACO Branch, FAA; or Transport Canada; or Bombardier, Inc.'s Transport Canada Design Approval Organization (DAO). If approved by the DAO, the approval must include the DAO-authorized signature.

(j) Additional Information

(1) Refer to Transport Canada AD CF–2022–10, dated March 10, 2022, for related information. This Transport Canada AD may be found in the AD docket at *regulations.gov* under Docket No. FAA–2022–1572.

(2) For more information about this AD, contact Chirayu Gupta, Aerospace Engineer, Mechanical Systems and Administrative Services Section, FAA, New York ACO Branch, 1600 Stewart Avenue, Suite 410, Westbury, NY 11590; telephone 516–228–7300; email *9-avs-nyaco-cos@faa.gov*.

(k) Material Incorporated by Reference

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

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

(i) Bombardier Service Bulletin 600–0778, dated September 22, 2021.

(ii) Bombardier Service Bulletin 601–1110, dated September 22, 2021.

(iii) Bombardier Service Bulletin 604–25–004, dated September 22, 2021.

(iv) Bombardier Service Bulletin, 605–25–014, dated September 22, 2021.

(v) Bombardier Service Bulletin, 650–25–016, dated September 22, 2021.

(3) For service information identified in this AD, contact Bombardier Business Aircraft Customer Response Center, 400 Côte-Vertu Road West, Dorval, Québec H4S 1Y9, Canada; telephone 514–855–2999; email *ac.yul@aero.bombardier.com*; website: *bombardier.com*.

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

(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 December 1, 2022.

Christina Underwood,

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

[FR Doc. 2022–26471 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2022–1245; Project Identifier MCAI–2022–00503–T]

RIN 2120–AA64

Airworthiness Directives; ATR—GIE Avions de Transport Régional Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: The FAA proposes to supersede Airworthiness Directive (AD) 2021–20–09, which applies to certain ATR—GIE Avions de Transport Régional Model ATR72 airplanes. AD 2021–20–09 requires revising the existing maintenance or inspection program, as applicable, to incorporate new or more restrictive airworthiness limitations. Since the FAA issued AD 2021–20–09, the FAA has determined that new or more restrictive tasks and airworthiness limitations are necessary. This proposed AD would continue to require the actions in AD 2021–20–09 and require revising the existing maintenance or inspection program, as applicable, to incorporate additional new or more restrictive tasks and airworthiness limitations, as specified in a European Union Aviation Safety Agency (EASA) AD, which is proposed for incorporation by reference. The FAA is proposing this AD to address the unsafe condition on these products.

DATES: The FAA must receive comments on this proposed AD by January 20, 2023.

ADDRESSES: You may send comments, using the procedures found in 14 CFR 11.43 and 11.45, by any of the following methods:

- *Federal eRulemaking Portal:* Go to *regulations.gov*. Follow the instructions for submitting comments.
- *Fax:* 202–493–2251.
- *Mail:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590.
- *Hand Delivery:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For EASA material that that is proposed for IBR in this NPRM, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; telephone +49 221 8999 000; email *ADs@easa.europa.eu*; website *easa.europa.eu*. You may find this material on the EASA website at *ad.easa.europa.eu*. You may view this material at the FAA, Airworthiness Products Section, Operational Safety Branch, 2200 South 216th St., Des Moines, WA. For information on the availability of this material at the FAA, call 206–231–3195. It is also available in the AD docket at *regulations.gov* by searching for and locating Docket No. FAA–2022–1245.

Examining the AD Docket

You may examine the AD docket at *regulations.gov* by searching for and locating Docket No. FAA–2022–1245; 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 NPRM, the mandatory continuing airworthiness information (MCAI), any comments received, and other information. The street address for Docket Operations is listed above.

FOR FURTHER INFORMATION CONTACT: Shahram Daneshmandi, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th St., Des Moines, WA 98198; telephone 206–231–3220; email *shahram.daneshmandi@faa.gov*.

SUPPLEMENTARY INFORMATION:

Comments Invited

The FAA invites you to send any written relevant data, views, or arguments about this proposal. Send your comments to an address listed under **ADDRESSES**. Include ''Docket No. FAA–2022–1245; Project Identifier MCAI–2022–00503–T'' at the beginning of your comments. The most helpful comments reference a specific portion of the proposal, explain the reason for any recommended change, and include supporting data. The FAA will consider all comments received by the closing date and may amend this proposal because of those comments.

Except for Confidential Business Information (CBI) as described in the following paragraph, and other information as described in 14 CFR 11.35, the FAA will post all comments received, without change, to *regulations.gov,* including any personal information you provide. The agency will also post a report summarizing each substantive verbal contact received about this NPRM.

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 NPRM 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 NPRM, it is important that you clearly designate the submitted comments as CBI. Please mark each page of your submission containing CBI as ''PROPIN.'' The FAA will treat such marked submissions as confidential under the FOIA, and they will not be placed in the public docket of this NPRM. Submissions containing CBI should be sent to Shahram Daneshmandi, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th St., Des Moines, WA 98198; telephone 206–231–3220; email *shahram.daneshmandi@faa.gov*. Any commentary that the FAA receives which is not specifically designated as CBI will be placed in the public docket for this rulemaking.

Background

The FAA issued AD 2021–20–09, Amendment 39–21747 (86 FR 64805, November 19, 2021) (AD 2021–20–09), which applies to certain ATR—GIE Avions de Transport Régional Model ATR72–101, –102, –201, –202, –211, –212, and –212A airplanes. AD 2021–20–09 requires revising the existing maintenance or inspection program, as applicable, to incorporate new or more restrictive airworthiness limitations. The FAA issued AD 2021–20–09 to address reduced structural integrity of the airplane.

Actions Since AD 2021–20–09 Was Issued

Since the FAA issued AD 2021–20–09, the FAA has determined that new or more restrictive tasks and airworthiness limitations are necessary.

EASA, which is the Technical Agent for the Member States of the European Union, has issued EASA AD 2022–0201, dated September 26, 2022 (EASA AD 2022–0201) (also referred to as the MCAI), to correct an unsafe condition for all ATR—GIE Avions de Transport Régional Model ATR72–101, –102, –201, –202, –211, –212, and –212A airplanes.

Airplanes with an original airworthiness certificate or original export certificate of airworthiness issued after February 3, 2022, must comply with the airworthiness limitations specified as part of the approved type design and referenced on the type certificate data sheet; this AD therefore does not include those airplanes in the applicability.

This proposed AD was prompted by a determination that new or more restrictive tasks and airworthiness limitations are necessary. The FAA is proposing this AD to address fatigue cracking and damage in principal structural elements, which could result in reduced structural integrity of the airplane. See the MCAI for additional background information.

Related Service Information Under 1 CFR Part 51

EASA AD 2022–0201 describes new or more restrictive tasks, airworthiness limitations for airplane structures, and safe life limits.

This proposed AD would also require EASA AD 2021–0020, dated January 15, 2021 (EASA AD 2021–0020), which the Director of the Federal Register approved for incorporation by reference as of December 27, 2021 (86 FR 64805, November 19, 2021).

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 the **ADDRESSES** section.

FAA's Determination

This product has been approved by the aviation authority of another country and is approved for operation in the United States. Pursuant to the FAA's bilateral agreement with the State of Design Authority, it has notified the FAA of the unsafe condition described in the MCAI referenced above. The FAA is issuing this NPRM after determining that the unsafe condition described previously is likely to exist or develop in other products of the same type design.

Proposed AD Requirements in This NPRM

This proposed AD would retain the requirements of AD 2021–20–09. This proposed AD would also require revising the existing maintenance or inspection program, as applicable, to incorporate new or more restrictive tasks and airworthiness limitations, which are specified in EASA AD 2022–0201 described previously, as proposed for incorporation by reference. Any differences with EASA AD 2022–0201 are identified as exceptions in the regulatory text of this AD.

This proposed AD would require revisions to certain operator maintenance documents to include new actions (*e.g.,* inspections). Compliance with these actions is required by 14 CFR 91.403(c). For airplanes that have been previously modified, altered, or repaired in the areas addressed by this proposed AD, the operator may not be able to accomplish the actions described in the revisions. In this situation, to comply with 14 CFR 91.403(c), the operator must request approval for an alternative method of compliance (AMOC) according to paragraph (m)(1) of this proposed AD.

Explanation of Required Compliance Information

In the FAA's ongoing efforts to improve the efficiency of the AD process, the FAA developed a process to use some civil aviation authority (CAA) ADs as the primary source of information for compliance with requirements for corresponding FAA ADs. The FAA has been coordinating this process with manufacturers and CAAs. As a result, the FAA proposes to retain the IBR of EASA AD 2021–0020 and incorporate EASA AD 2022–0201 by reference in the FAA final rule. This proposed AD would, therefore, require compliance with EASA AD 2021–0020 and EASA AD 2022–0201 in their entirety through that incorporation, except for any differences identified as exceptions in the regulatory text of this proposed AD. Using common terms that are the same as the heading of a particular section in EASA AD 2021–0020 or EASA AD 2022–0201 does not mean that operators need comply only with that section. For example, where the AD requirement refers to ''all required actions and compliance times,'' compliance with this AD requirement is not limited to the section titled ''Required Action(s) and Compliance Time(s)'' in EASA AD 2021–0020 or EASA AD 2022–0201. Service information required by EASA AD 2021–0020 and EASA AD 2022–0201 for compliance will be available at *regulations.gov* by searching for and locating Docket No. FAA–2022–1245 after the FAA final rule is published.

Airworthiness Limitation ADs Using the New Process

The FAA's process of incorporating by reference MCAI ADs as the primary source of information for compliance with corresponding FAA ADs has been limited to certain MCAI ADs (primarily those with service bulletins as the primary source of information for accomplishing the actions required by the FAA AD). However, the FAA is now expanding the process to include MCAI ADs that require a change to airworthiness limitation documents, such as airworthiness limitation sections.

For these ADs that incorporate by reference an MCAI AD that changes airworthiness limitations, the FAA requirements are unchanged. Operators must revise the existing maintenance or inspection program, as applicable, to incorporate the information specified in the new airworthiness limitation document. The airworthiness limitations must be followed according to 14 CFR 91.403(c) and 91.409(e).

The previous format of the airworthiness limitation ADs included a paragraph that specified that no alternative actions (*e.g.,* inspections), or intervals may be used unless the actions and intervals are approved as an AMOC in accordance with the procedures specified in the AMOCs paragraph under ''Additional FAA Provisions.'' This new format includes a ''New Provisions for Alternative Actions and Intervals'' paragraph that does not specifically refer to AMOCs, but operators may still request an AMOC to use an alternative action or interval.

Costs of Compliance

The FAA estimates that this proposed AD affects 23 airplanes of U.S. registry. The FAA estimates the following costs to comply with this proposed AD:

The FAA estimates the total cost per operator for the retained actions from AD 2021–20–09 to be $7,650 (90 work-hours × $85 per work-hour).

The FAA has determined that revising the existing maintenance or inspection program takes an average of 90 work-hours per operator, although the agency recognizes that this number may vary from operator to operator. Since operators incorporate maintenance or inspection program changes for their affected fleet(s), the FAA has determined that a per-operator estimate is more accurate than a per-airplane estimate.

The FAA estimates the total cost per operator for the new proposed actions to be $7,650 (90 work-hours × $85 per work-hour).

Authority for This Rulemaking

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

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

Regulatory Findings

The FAA determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would 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 this proposed regulation:

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

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

(3) Would 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 Proposed Amendment

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

PART 39—AIRWORTHINESS DIRECTIVES

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

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

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by:

■ a. Removing Airworthiness Directive (AD) 2021–20–09, Amendment 39–21747 (86 FR 64805, November 19, 2021) (AD 2021–20–09); and

■ b. Adding the following new AD:

ATR—GIE Avions de Transport Régional: Docket No. FAA–2022–1245; Project Identifier MCAI–2022–00503–T.

(a) Comments Due Date

The FAA must receive comments on this airworthiness directive (AD) by January 20, 2023.

(b) Affected ADs

This AD replaces AD 2021–20–09, Amendment 39–21747 (86 FR 64805, November 19, 2021) (AD 2021–20–09).

(c) Applicability

This AD applies to ATR—GIE Avions de Transport Régional Model ATR72–101, –102, –201, –202, –211, –212, and –212A airplanes, certificated in any category, with an original airworthiness certificate or original export certificate of airworthiness issued on or before February 3, 2022.

(d) Subject

Air Transport Association (ATA) of America Code 05, Time Limits/Maintenance Checks.

(e) Unsafe Condition

This AD was prompted by a determination that new or more restrictive tasks and airworthiness limitations are necessary. The FAA is issuing this AD to address fatigue cracking and damage in principal structural elements, which could result in reduced structural integrity of the airplane.

(f) Compliance

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

(g) Retained Revision of the Existing Maintenance or Inspection Program, With No Changes

This paragraph restates the requirements of paragraph (j) of AD 2021–20–09, with no changes. For ATR—GIE Avions de Transport Régional Model ATR72–101, –102, –201, –202, –211, –212, and –212A airplanes, certificated in any category, with an original airworthiness certificate or original export certificate of airworthiness issued on or before October 9, 2020, Except as specified in paragraph (h) of this AD: Comply with all required actions and compliance times specified in, and in accordance with, European Union Aviation Safety Agency (EASA) AD 2021–0020, dated January 15, 2021 (EASA AD 2021–0020). Accomplishing the revision of the existing maintenance or inspection program required by paragraph (j) of this AD terminates the requirements of this paragraph.

(h) Retained Exceptions to EASA AD 2021–0020, With No Changes

This paragraph restates the requirements of paragraph (k) of AD 2021–20–09, with no changes.

(1) Where EASA AD 2021–0020 refers to its effective date, this AD requires using December 27, 2021 (the effective date of AD 2021–20–09).

(2) The requirements specified in paragraphs (1) and (2) of EASA AD 2021–0020 do not apply to this AD.

(3) Paragraph (3) of EASA AD 2021–0020 specifies revising ''the approved AMP'' within 12 months after its effective date, but this AD requires revising the existing maintenance or inspection program, as applicable, within 90 days after December 27, 2021 (the effective date of AD 2021–20–09).

(4) Except as provided by Note 1 of EASA AD 2021–0020, the initial compliance time for doing the tasks specified in paragraph (3) of EASA AD 2021–0020 is at the applicable ''thresholds'' as incorporated by the requirements of paragraph (3) of EASA AD 2021–0020, or within 90 days after December 27, 2021 (the effective date of AD 2021–20–09), whichever occurs later.

(5) The provisions specified in paragraphs (4) and (5) of EASA AD 2021–0020 do not apply to this AD.

(6) The ''Remarks'' section of EASA AD 2021–0020 does not apply to this AD.

(i) Retained Restrictions on Alternative Actions and Intervals, With a New Exception

This paragraph restates the requirements of paragraph (l) of AD 2021–20–09, with a new exception. Except as required by paragraph (j) of this AD, after the existing maintenance or inspection program has been revised as required by paragraph (g) of this AD, no alternative actions (*e.g.,* inspections) and intervals are allowed unless they are approved as specified in the provisions of the ''Ref. Publications'' section of EASA AD 2021–0020.

(j) New Revision of the Existing Maintenance or Inspection Program

Except as specified in paragraph (k) of this AD: Comply with all required actions and compliance times specified in, and in accordance with, EASA AD 2022–0201, dated September 26, 2022 (EASA AD 2022–0201). Accomplishing the revision of the existing maintenance or inspection program required by this paragraph terminates the requirements of paragraph (g) of this AD.

(k) Exceptions to EASA AD 2022–0201

(1) Where EASA AD 2022–0201 refers to its effective date, this AD requires using the effective date of this AD.

(2) The requirements specified in paragraphs (1) and (2) of EASA AD 2022–0201 do not apply to this AD.

(3) Paragraph (3) of EASA AD 2022–0201 specifies revising ''the approved AMP'' within 12 months after its effective date, but this AD requires revising the existing maintenance or inspection program, as applicable, within 90 days after the effective date of this AD.

(4) The initial compliance time for doing the tasks specified in paragraph (3) of EASA AD 2022–0201 is at the applicable ''limitations'' and ''associated thresholds'' as incorporated by the requirements of paragraph (3) of EASA AD 2022–0201, or within 90 days after the effective date of this AD, whichever occurs later.

(5) The provisions specified in paragraphs (4) and (5) of EASA AD 2022–0201 do not apply to this AD.

(6) The ''Remarks'' section of EASA AD 2022–0201 does not apply to this AD.

(l) New Provisions for Alternative Actions and Intervals

After the existing maintenance or inspection program has been revised as required by paragraph (j) of this AD, no alternative actions (*e.g.,* inspections) and intervals are allowed unless they are approved as specified in the provisions of the ''Ref. Publications'' section of EASA AD 2022–0201.

(m) Additional FAA AD Provisions

The following provisions also apply to this AD:

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

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

(n) Related Information

For more information about this AD, contact Shahram Daneshmandi, Aerospace Engineer, Large Aircraft Section, FAA, International Validation Branch, 2200 South 216th St., Des Moines, WA 98198; telephone 206–231–3220; email *shahram.daneshmandi@faa.gov.*

(o) Material Incorporated by Reference

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

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

(3) The following service information was approved for IBR on [DATE 35 DAYS AFTER PUBLICATION OF THE FINAL RULE].

(i) European Union Aviation Safety Agency (EASA) AD 2022–0201, dated September 26, 2022.

(ii) [Reserved]

(4) The following service information was approved for IBR on December 27, 2021 (86 FR 64805, November 19, 2021).

(i) European Union Aviation Safety Agency (EASA) AD 2021–0020, dated January 15, 2021.

(ii) [Reserved]

(5) For EASA AD 2022–0201 and AD 2021–0020, contact EASA, Konrad-Adenauer-Ufer 3, 50668 Cologne, Germany; telephone +49 221 8999 000; email *ADs@easa.europa.eu;* website *easa.europa.eu.* You may find these EASA ADs on the EASA website at *ad.easa.europa.eu.*

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

(7) 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 December 1, 2022.

Christina Underwood,

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

[FR Doc. 2022–26468 Filed 12–5–22; 8:45 am]

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM22–12–000]

Reliability Standards To Address Inverter-Based Resources

AGENCY: Federal Energy Regulatory Commission, Department of Energy (DOE).

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to direct the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), to develop new or modified Reliability Standards that address the following reliability gaps related to inverter-based resources (IBR): data sharing; model validation; planning and operational studies; and performance requirements. Further, the Commission proposes to direct NERC to submit to the Commission a compliance filing within 90 days of the effective date of the final rule in this proceeding that includes a detailed, comprehensive standards development and implementation plan to ensure all new or modified Reliability Standards necessary to address the IBR-related reliability gaps identified in the final rule are submitted to the Commission within 36 months of Commission approval of the plan.

DATES: Comments are due February 6, 2023 and reply Comments are due March 6, 2023.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways. Electronic filing through *https://www.ferc.gov,* is preferred.

- *Electronic Filing:* Documents must be filed in acceptable native applications and print-to-PDF, but not in scanned or picture format.
- For those unable to file electronically, comments may be filed by U.S. Postal Service mail or by hand (including courier) delivery.
  - *Mail via U.S. Postal Service only:* Addressed to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street NE, Washington, DC 20426.
  - *For Delivery via Any Other Carrier (including courier):* Deliver to: Federal Energy Regulatory Commission, Office of the Secretary, 12225 Wilkins Avenue, Rockville, MD 20852.

FOR FURTHER INFORMATION CONTACT:

Eugene Blick (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 502–8803, *Eugene.Blick@ferc.gov.*

Alan J. Rukin (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 502–8502, *Alan.Rukin@ferc.gov.*

SUPPLEMENTARY INFORMATION:

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I. Introduction

1. Pursuant to section 215(d)(5) of the Federal Power Act (FPA),[1] the Commission proposes to direct NERC, the Commission-certified ERO, to submit new or modified Reliability Standards that address concerns pertaining to the impacts of IBRs [2] on the reliable operation [3] of the Bulk-Power System.[4] The Commission proposes to direct NERC to develop new or modified Reliability Standards addressing four reliability gaps pertaining to IBRs: (1) data sharing; (2) model validation; (3) planning and operational studies; and (4) performance requirements.

2. We take this action in view of the rapid change in the generation resource mix currently underway on the Bulk-Power System, including the addition of an ''unprecedented proportion of nonsynchronous resources'' [5] projected over the next decade, including many resources that employ inverters and converters [6] to provide energy to the Bulk-Power System. According to NERC, the rapid integration of IBRs is ''the most significant driver of grid transformation'' on the Bulk-Power System.[7] While IBRs provide many benefits, they also present new considerations for transmission planning and operation of the Bulk-Power System.

3. IBRs can produce real and reactive power like synchronous generators, but IBRs do not react to disturbances on the Bulk-Power System in the same way. For example, synchronous resources that are not connected to a fault will automatically ride through [8] a disturbance because they are synchronized (*i.e.,* connected at identical speeds) to the electric power system and physically linked to support the system voltage or frequency during voltage or frequency fluctuations by continuing to produce real and reactive power. In contrast, IBRs are not directly synchronized to the electric power system and must be programmed to support the electric power system and to ride through a disturbance. The operational characteristics of IBRs coupled with their equipment settings may cause them to reduce power output, whether by tripping offline [9] or ceasing operation without tripping offline (known as momentary cessation),[10] individually or in the aggregate in response to response to a single fault on a transmission or sub-transmission system. Such occurrences may exacerbate system disturbances and have a material impact on the reliable operation of the Bulk-Power System.

4. The mandatory and enforceable Reliability Standards were developed to apply to the generation resources prevalent at the time that the standards were developed and adopted—nearly exclusively synchronous generation resources—and ensure the reliable operation of the Bulk-Power System. As a result, the Reliability Standards may

[1] 16 U.S.C. 824o(d)(5); 18 CFR 39.5(f).

[2] This notice of proposed rulemaking (NOPR) uses the term IBR generally to include all generation resources that connect to the electric power system using power electronic devices that change direct current (DC) power produced by a resource to alternating current (AC) power compatible with distribution and transmission grids. IBRs may refer to solar photovoltaic (PV), wind, fuel cell, and battery storage resources.

[3] The FPA defines reliable operation as operating the elements of the Bulk-Power System within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements. 16 U.S.C. 824o(a)(4); *see also* 18 CFR 39.1.

[4] The Bulk-Power System is defined in the FPA as facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. 16 U.S.C. 824o(a)(1); *see also* 18 CFR 39.1.

[5] NERC, *2020 Long Term Reliability Assessment Report,* 9 (Dec. 2020), *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf* (2020 LTRA Report).

[6] An inverter is a power electronic device that inverts DC power to AC sinusoidal power through solid state switches. A converter is a power electronic device that converts AC sinusoidal power to DC power through solid state switches. Consistent with NERC's terminology, this order uses the term ''inverter'' to refer to generating facilities that use power electronic inversion and conversion. NERC, *Inverter-Based Resource Performance and Analysis Technical Workshop,* 29 (Feb. 2019), *https://www.nerc.com/comm/PC/IRPTF%20Workshops/IRPTF_Workshop_Presentations.pdf.*

[7] NERC, *Inverter-Based Resource Strategy: Ensuring Reliability of the Bulk Power System with Increased Levels of BPS-Connected IBRs,* 1 (Sept. 2022), *https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf* (NERC IBR Strategy).

[8] *See Standardization of Generator Interconnection Agreements & Procs.,* Order No. 2003, 68 FR 49846 (Aug. 19, 2003), 104 FERC ¶ 61,103, at P 562 n.88, (2003) (defining ride through as ''a Generating Facility staying connected to and synchronized with the Transmission System during system disturbances within a range of over- and under-frequency[/voltage] conditions, in accordance with Good Utility Practice.'').

[9] Tripping offline is a mode of operation during which part of or the entire IBR disconnects from the Bulk-Power System and/or distribution system and therefore cannot supply real and reactive power.

[10] Momentary cessation is a mode of operation during which the inverter remains electrically connected to the Bulk-Power System, but the inverter does not inject current during low or high voltage conditions outside the continuous operating range. As a result, there is no current injection from the inverter and therefore no active or reactive current (and no active or reactive power). NERC, *Reliability Guideline: Bulk-Power System-Connected Inverter-Based Resource Performance,* 11 (Sept. 2018), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Inverter-Based_Resource_Performance_Guideline.pdf* (IBR Performance Guideline).

not account for the material technological differences between the response of synchronous generation resources and that of IBRs to the same disturbances on the Bulk-Power System.[11] Illustratively, at least 12 events on the Bulk-Power System [12] have demonstrated common mode failures of IBRs regardless of their size or voltage connection, acting unexpectedly and adversely in response to normally cleared transmission line faults on the Bulk-Power System.[13] Further, simulations indicate that IBR momentary cessation occurring in the aggregate can lead to instability, system-wide uncontrolled separation, and voltage collapse.[14]

5. We preliminarily find that the Reliability Standards may not provide Bulk-Power System planners or operators with the tools necessary to plan for and reliably integrate IBRs into the Bulk-Power System. Further, we preliminarily find that the Reliability Standards may not provide Bulk-Power System planners or operators with the tools necessary to plan for IBR–DERs connected to the distribution system that, when acting in the aggregate, can have a material impact on the reliable operation of the Bulk-Power System. Additionally, we preliminary find that the Reliability Standards do not delineate all of the performance requirements that are unique to IBRs and are necessary to ensure that IBRs operate in a predictable and reliable manner. We propose to act to ensure the continued reliable operation of the Bulk-Power System in response to current, and in anticipation of greater, IBR penetration onto the Bulk-Power System. We therefore propose, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of the Commission's regulations, to direct NERC to develop new or modified Reliability Standards that address the following specific matters for IBRs: [15]

- *IBR Data Sharing:* The Reliability Standards should ensure that NERC registered entities,[16] such as planning coordinators and reliability coordinators, have the necessary data to predict the behavior of all IBRs, including unregistered IBRs and IBR–DERs, and their impact on the reliable operation of the Bulk-Power System. To achieve this, the Reliability Standards should ensure that generator owners, transmission owners, and distribution providers are required to share validated modeling, planning, operations, and disturbance monitoring data for IBRs with planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities.
- *IBR Model Validation:* The Reliability Standards should ensure that IBR models are comprehensive, validated, and updated in a timely manner, so that they can adequately predict the behavior of all IBRs, including unregistered IBRs and IBR–DERs, and their impacts on the reliable operation of the Bulk-Power System.
- *IBR Planning and Operational Studies:* The Reliability Standards should ensure that validated IBR models are included in planning and operational studies to assess the reliability impacts on Bulk-Power System performance by registered IBRs and unregistered IBRs, both individually and in the aggregate, as well as IBR–DERs in the aggregate. The Reliability Standards should ensure that planning and operational studies assess the impacts of all IBRs within and across planning and operational boundaries for normal operations and contingency event conditions.
- *IBR Performance Requirements:* The Reliability Standards should ensure that registered IBRs provide frequency and voltage support during frequency and voltage excursions in a manner necessary to contribute toward the overall system needs for essential reliability services.[17] The Reliability Standards should establish clear and reliable technical limits and capabilities for registered IBRs to ensure that all registered IBRs are operated in a predictable and reliable manner during: (1) normal operations; and (2) contingency event conditions. The Reliability Standards should require that the engineering and operational aspects of registered IBRs necessary to contribute toward the overall system needs for essential reliability services include registered IBR post-disturbance ramp rates and phase-locked loop synchronization.

6. In proposing to direct that NERC develop one or more new Reliability

[11] *See, e.g.,* NERC, *2013 Long-Term Reliability Assessment,* 22 (Dec. 2013), *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf* (2013 LTRA Report) (finding that reliably integrating high levels of variable resources into the Bulk-Power System would require ''significant changes to traditional methods used for system planning and operation,'' including requiring ''new tools and practices, including potential enhancements to . . . Reliability Standards or guidelines to maintain [Bulk-Power System] reliability.'').

[12] The 12 events report an average of approximately 1,000 MW of IBRs entering into momentary cessation or tripping in the aggregate. The 12 Bulk-Power System events are: (1) the Blue Cut Fire (August 16, 2016); (2) the Canyon 2 Fire (October 9, 2017); (3) Angeles Forest (April 20, 2018); (4) Palmdale Roost (May 11, 2018); (5) San Fernando (July 7, 2020); (6) the first Odessa, Texas event (May 9, 2021); (7) the second Odessa, Texas event (June 26, 2021); (8) Victorville (June 24, 2021); (9) Tumbleweed (July 4, 2021); (10) Windhub (July 28, 2021); (11) Lytle Creek (August 26, 2021), and (12) Panhandle Wind Disturbance (March 22, 2022).

[13] The Bulk-Power System's sensing devices usually respond slowly, and therefore, are likely underreporting the size of the IBR generation loss during disturbances. *See, e.g.,* NERC and Western Electricity Coordinating Council (WECC), *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report,* 1 n.6 (Feb. 2018), *https://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%202%20Fire%20Disturbance%20Report/900%20MW%20Solar%20Photovoltaic%20Resource%20Interruption%20Disturbance%20Report.pdf* (Canyon 2 Fire Event Report) (explaining that MW loss values are based on supervisory control and data acquisition (SCADA), which does not capture momentary cessation). NERC only tracks ''Category 1'' events, which are unexpected outages of three or more bulk electric system facilities, including interruptions of IBRs aggregated to a 500 MW threshold (Category 1aii and Category 1i). NERC, *ERO Event Analysis Process—Version 4.0,* 2 (Dec. 2019), *https://www.nerc.com/pa/rrm/ea/ERO_EAP_Documents%20DL/ERO_EAP_v4.0_final.pdf.*

[14] *See* NERC, *Resource Loss Protection Criteria Assessment Whitepaper,* (Feb. 2018), *https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/IRPTF_RLPC_Assessment.pdf* (Resource Loss Protection Whitepaper) (demonstrating the impacts of momentary cessation risks to Bulk-Power System reliability through simulations).

[15] Various NERC reports do not always differentiate between IBRs based on type, or between those subject to Reliability Standards and those located on the distribution system. Where necessary to qualify our proposed directives, however, we differentiate between IBRs registered with NERC and therefore subject to the Reliability Standards because they fall within the bulk electric system definition (registered IBRs) from those connected directly to the Bulk-Power System but not registered with NERC and therefore not subject to the Reliability Standards (unregistered IBRs), and those connected to the distribution system (IBR–DER). NERC's Commission-approved bulk electric system definition is a subset of the Bulk-Power System and defines the scope of the Reliability Standards and the entities subject to NERC compliance. *Revisions to Electric Reliability Org. Definition of Bulk Elec. Sys. & Rules of Proc.,* Order No. 773, 78 FR 804 (Jan. 4, 2013), 141 FERC ¶ 61,236 (2012) *order on reh'g,* Order No. 773–A, 78 FR 29209 (May 17, 2013), 143 FERC ¶ 61,053 (2013) *rev'd sub nom. People of the State of N.Y.* v. *FERC,* 783 F.3d 946 (2d Cir. 2015); NERC, *Glossary of Terms Used in NERC Reliability Standards,* 5–7 (Mar. 29, 2022), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf* (NERC Glossary).

[16] NERC identifies and registers Bulk-Power System users, owners, and operators who are responsible for performing specified reliability functions to which requirements of mandatory Reliability Standards are applicable. *See* NERC Rules of Procedure, Section 500 (Organization Registration and Certification).

[17] *See, e.g.,* NERC, *A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability,* vi (Oct. 2014), *https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf* (Essential Reliability Services Concept Paper) (listing the essential reliability services necessary to maintain Bulk-Power System reliability).

Standards or modify currently effective Reliability Standards to address the gaps identified in this rulemaking, we are not proposing specific requirements. Instead, we identify concerns that we believe the Reliability Standards should address. In its petition accompanying any new or modified Reliability Standards, NERC should explain how the new or modified Reliability Standards address the Commission's concerns.[18] We invite comments on these concerns and whether there are other concerns related to planning for and integrating IBRs that the Commission should direct NERC to address in this or a future proceeding.

7. We propose to direct NERC to submit a compliance filing within 90 days of the effective date of the final rule in this proceeding. That compliance filing shall include a detailed, comprehensive standards development and implementation plan explaining how NERC will prioritize the development and implementation of new or modified Reliability Standards. In its compliance filing, NERC should explain how it is prioritizing its IBR Reliability Standard projects to meet the directives in the final rule, taking into account the risk posed to the reliability of the Bulk-Power System, standard development projects already underway, resource constraints, and other factors if necessary.

8. We seek comment on the proposal to direct NERC to use a staggered approach that would result in NERC submitting new or modified Reliability Standards in three stages: (1) new or modified Reliability Standards including directives related to registered IBR failures to ride through frequency and voltage variations during normally cleared Bulk-Power System faults shall be filed with the Commission within 12 months of Commission approval of the plan; (2) new or modified Reliability Standards addressing the interconnected directives related to registered IBR, unregistered IBR, and IBR–DER data sharing, registered IBR disturbance monitoring data sharing, registered IBR, unregistered IBR, and IBR–DER data and model validation, and registered IBR, unregistered IBR, and IBR–DER planning and operational studies shall be filed with the Commission within 24 months of Commission approval of the plan; and (3) new or modified Reliability Standards including the remaining directives for post-disturbance ramp rates and phase-locked loop synchronization shall be filed with the Commission within 36 months of Commission approval of the plan. We believe this staggered approach to standard development may be necessary based on the scope of work anticipated and that specific target dates will provide a valuable tool and incentive to NERC to timely address the directives in the final rule. This proposal strikes a reasonable balance between the need to timely implement identified improvements to the Reliability Standards that will further Bulk-Power System reliability and the need for NERC to develop modifications with appropriate stakeholder input using its open stakeholder process.

9. In view of the rapid growth of IBRs connected to the Bulk-Power System, we are issuing this NOPR concurrently with a separate order in Docket No. RD22–4–000 directing NERC to address the registration of owners and operators of unregistered IBRs that may have a material impact on the reliable operation of the Bulk-Power System.[19] That order addresses the registration of unregistered IBRs that individually fall outside of the bulk electric system definition, are connected directly to the Bulk-Power System, and that in the aggregate have a material impact on the reliable operation of the Bulk-Power System.

II. Background

A. Legal Authority

10. Section 215 of the FPA provides that the Commission may certify an ERO, the purpose of which is to establish and enforce Reliability Standards, which are subject to Commission review and approval. Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently.[20] Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[21] and subsequently certified NERC as the ERO.[22]

11. The Commission has the authority pursuant to section 215(d)(5) of the FPA and consistent with § 39.5(f) of the Commission's regulations, upon its own motion or upon complaint, to order the ERO to submit to the Commission a proposed Reliability Standard or a modification to a Reliability Standard that addresses a specific matter if the Commission considers such a new or modified Reliability Standard appropriate to carry out section 215 of the FPA.[23] Further, pursuant to § 39.5(g) of the Commission's regulations, when ordering the ERO to submit to the Commission a proposed or modified Reliability Standard that addresses a specific matter, the Commission may order a deadline by which the ERO must submit such Reliability Standard.[24]

B. Reliability Impacts of IBR Technologies

12. Until recently, the Bulk-Power System generation fleet was composed almost exclusively of synchronous generation resources[25] that convert mechanical energy into electric energy through electromagnetic induction. By virtue of their large rotating elements, these synchronous generation resources inherently resist changes in system frequency due to the kinetic energy in their rotating components, providing time for other governor controls (when properly configured) to maintain supply and load balance. Similarly, synchronous generation resources can provide voltage support during voltage disturbances.

13. In contrast, IBRs do not use electromagnetic induction from machinery that is directly synchronized to the Bulk-Power System. Instead, IBRs predominantly use grid-following inverters, which rely on sensed information from the grid (*e.g.,* a voltage waveform) in order to produce the desired AC real and reactive power

[18] *See, e.g., Mandatory Reliability Standards for the Bulk-Power Sys.,* Order No. 693, 72 FR 16416 (Apr. 4, 2007), 118 FERC ¶ 61,218, at PP 186, 297, *order on reh'g,* Order No. 693–A, 72 FR 40717 (July 25, 2007), 120 FERC ¶ 61,053 (2007) (''where the Final Rule identifies a concern and offers a specific approach to address the concern, we will consider an equivalent alternative approach provided that the ERO demonstrates that the alternative will address the Commission's underlying concern or goal as efficiently and effectively as the Commission's proposal'').

[19] *See Registration of Inverter-based Resources,* 181 FERC ¶ 61,124 (2022).

[20] 16 U.S.C. 824o(e).

[21] *Rules Concerning Certification of the Elec. Reliability Org. & Procs. for the Establishment, Approval, & Enf't of Elec. Reliability Standards,* Order No. 672, 71 FR 8662 (Feb. 17, 2006), 114 FERC ¶ 61,104, *order on reh'g,* Order No. 672–A, 71 FR 19814 (Apr. 18, 2006), 114 FERC ¶ 61,328 (2006).

[22] *N. Am. Elec. Reliability Corp.,* 116 FERC ¶ 61,062, *order on reh'g and compliance,* 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc.* v. *FERC,* 564 F.3d 1342 (DC Cir. 2009).

[23] 16 U.S.C. 824o(d)(5); 18 CFR 39.5(f).

[24] 18 CFR 39.5(g).

[25] The Reliability Standards use both terms ''generation resources'' and ''generation facilities'' to define sources of electric power on the transmission system. In this NOPR, we use the terms ''generation resources'' and ''generation facilities'' interchangeably.

output.[26] IBRs can track grid state parameters (*e.g.,* voltage angle) on the order of milli-seconds and react nearly instantaneously to changing grid conditions. Some IBRs, however, are not configured or programmed to support grid voltage and frequency and, as a result, will reduce power,[27] exhibit momentary cessation, or trip in response to variations in system voltage or frequency.[28] In other words, under certain conditions some IBRs cease to provide power to the Bulk-Power System due to how they are configured and programmed even though some models and simulations predict that IBRs maintain real power output and provide voltage and frequency support consistent with Reliability Standard PRC–024–2 (Generator Frequency and Voltage Protective Relay Settings).

14. IBRs are also more dispersed across the Bulk-Power System compared to synchronous generation resources, and both localized and interconnection-wide IBR issues must be identified, studied, and mitigated to preserve Bulk-Power System reliability. Although IBRs are typically smaller-megawatt (MW) facilities, they are at greater risk than synchronous generation resources of being lost (*i.e.,* ceasing to provide power to the Bulk-Power System) in the aggregate in response to a single fault on the transmission or sub-transmission systems. Such response can occur when individual IBR controls and equipment protection settings are not configured to ride through system disturbances.[29] Thus, the impact of IBRs is not restricted by the size of a single facility or an individual balancing authority area, but rather by the number of IBRs or percent of generation made up by IBRs within an interconnection. In areas of high IBR saturation, this type of aggregate response may have an impact much greater than the most severe single contingency (*i.e.,* the traditional worst-case N–1 contingency) [30] of a balancing authority area, potentially adversely affecting other balancing authority areas across an interconnection.[31] Unless IBRs are configured and programmed to ride through normally cleared transmission faults, the potential impact of losing IBRs individually or in the aggregate will continue to increase as IBRs are added to the Bulk-Power System and make up an increasing proportion of the resource mix.

15. Further, simulations conducted by the NERC Resource Subcommittee demonstrate that the risks to Bulk-Power System reliability posed by momentary cessation are greater than any of the IBR disturbances NERC has documented as being experienced thus far. These simulations indicate the potential for: (1) normally-cleared, three-phase faults at certain locations in the Western Interconnection that could result in upwards of 9,000 MW of solar PV IBRs entering momentary cessation across a large geographic region; (2) transient instability caused by excessive transfer of inter-area power flows during and after momentary cessation; and (3) a drop in frequency that falls below the first stage of under frequency load shedding in WECC, traditionally studied as the loss of the two Palo Verde nuclear units in Arizona (approximately 2,600 MW).[32] These simulation results indicate that IBR momentary cessation occurring in the aggregate can lead to instability, system-wide uncontrolled separation, and voltage collapse.

16. Although IBRs present risks that Bulk-Power System planners and operators must account for, IBRs also present new opportunities to support the grid and respond to abnormal grid conditions.[33] When appropriately programmed, IBRs can operate during greater frequency deviations (*i.e.,* a wider frequency range) than synchronous generation resources.[34] This operational flexibility, and the ability of IBRs to perform with precision and speed, offers increased Bulk-Power System performance capabilities and controls that could mitigate disturbances on the Bulk-Power System. For Bulk-Power System operators to harness the unique performance and control capabilities of IBRs, these resources must be properly configured and programmed to support grid voltage and frequency during normal and abnormal grid conditions and be accurately modeled and represented in transmission planning and operations models.

C. Actions To Address the Reliability Impact of IBR Technologies

17. NERC has begun to address some of the reliability risk posed by IBRs. Specifically, since the first documented disturbance event on the Bulk-Power System demonstrating common mode failures of IBRs in 2016, NERC has: (1) published seven reports on 12 disturbance events; [35] (2) issued two

[26] *See, e.g., NERC, 2021 Long Term Reliability Assessment Report,* 6 (Dec. 2021), *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf* (2021 LTRA Report) (''IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls, not mechanical characteristics.''); *see also generally,* Denholm et al., National Renewable Energy Laboratory, *Inertia and the Power Grid: A Guide Without the Spin,* NREL/TP–6120–73856, v (2020), *https://www.nrel.gov/docs/fy20osti/73856.pdf*.

[27] NERC and WECC, *San Fernando Disturbance,* 2 (Nov. 2020), *https://www.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf* (San Fernando Disturbance Report).

[28] *See Essential Reliability Servs. & the Evolving Bulk-Power Sys. Primary Frequency Response,* Order No. 842, 83 FR 9636 (Mar. 6, 2018), 162 FERC ¶ 61,128 , at P 19 (2018) (describing NERC's comment that increased IBR deployment alongside retirement of synchronous generation resources has contributed to the decline in primary frequency response); *see also* NERC, *Fast Frequency Response Concepts and Bulk Power System Reliability Needs,* 5 (Mar. 2020), *https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf* (Fast Frequency Response White Paper) (explaining that as the instantaneous penetration of IBRs with little or no inertia continues to increase, system rate of change of frequency after a loss of generation will increase and the time available to deliver frequency responsive reserves will shorten, and illustrating the steeper rate of change of frequency and the importance of speed of response).

[29] *See, e.g.,* Canyon 2 Fire Event Report at 19 (finding momentary cessation as a major cause for the loss of IBRs when voltages rose above 1.1 per unit or decreased below 0.9 per unit).

[30] The most severe single contingency, or the N–1 contingency, generally refers to the concept that a system must be able to withstand an unexpected failure or outage of a single system component and maintain reliable service at all times. *See, e.g.,* NERC Glossary at 17 (defining ''most severe single contingency'').

[31] *See, e.g.,* San Fernando Disturbance Report at vi (stating that ''[t]his event, as with past events, involved a significant number of solar PV resources reducing power output (either due to momentary cessation or inverter tripping) as a result of normally-cleared [Bulk-Power System] faults. The widespread nature of power reduction across many facilities poses risks to [Bulk-Power System] performance and reliability.'').

[32] Resource Loss Protection Whitepaper at 1–2, key findings 4, 7, 8.

[33] *See, e.g.,* IBR Performance Guideline at vii (finding that the power electronics aspects of IBRs ''present new opportunities in terms of grid control and response to abnormal grid conditions.'').

[34] *See, e.g.,* Fast Frequency Response White Paper at 11.

[35] The seven reports on the 12 disturbances are:

(1) NERC, *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report* (June 2017), *https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf* (Blue Cut Fire Event Report) (covering the Blue Cut Fire event (August 16, 2016));

(2) Canyon 2 Fire Event Report (covering the Canyon 2 Fire event (October 9, 2017));

(3) NERC and WECC, *April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report* (Jan. 2019), (Angeles Forest and Palmdale Roost Events Report), *https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf* (Angeles Forest and Palmdale Roost Events Report) (covering the Angeles Forest (April 20, 2018) and Palmdale Roost (May 11, 2018) events);

(4) San Fernando Disturbance Report (covering the San Fernando event (July 7, 2020));

(5) NERC and Texas RE, *Odessa Disturbance* (Sept. 2021), *https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf* (Odessa Disturbance Report) (covering events in Odessa, Texas on May 9, 2021 and June 26, 2021);

Continued

NERC Alerts addressing the loss of solar PV IBRs; [36] (3) issued three reliability guidelines; [37] (4) formed the IBR performance task force (IRPTF) [38] and a system planning impacts of distributed energy resources working group (SPIDERWG); (5) issued various technical reports regarding IBR data collection and performance; [39] and (6) issued an IBR strategy document.[40] The NERC materials (*e.g.,* guidelines, whitepapers, reports, alerts, etc.) cited in this NOPR are also listed in Appendix A as a reference. Appendix A will not appear in the **Federal Register**. Appendix A will be available separately on the Commission's website.[41]

18. The only NERC actions that required a response from entities are the two NERC alerts addressing the loss of solar PV IBRs (both alerts were level 2 alerts, ''Recommendation to Industry'').[42] These NERC level 2 alerts recommended specific voluntary action to be taken by registered IBRs and required that the registered IBRs provide responsive information to NERC. While unregistered IBRs could also voluntarily take the specific actions set out in the level 2 alert, there was no reporting requirement for unregistered IBRs due to NERC's authority to require reporting responses only from registered IBRs. NERC issued these alerts to assess the scope of and recommend performance actions to address registered IBR reliability risks to the Bulk-Power System. NERC issued its first alert in 2017 after the Blue Cut Fire Event to collect data to assess the extent of the condition and to provide recommended performance improvements for existing and newly interconnecting solar PV IBRs connected to the Bulk-Power System.[43] NERC issued its second alert in 2018 after the Canyon 2 Fire event to recommend performance improvements including eliminating momentary cessation for registered IBRs already in operation.[44]

19. NERC formed the IRPTF in response to the findings and recommendations of the Blue Cut Fire Event Report in order to explore the performance characteristics of Bulk-Power System connected IBRs. The IRPTF is composed of subject matter experts and representatives from a variety of companies, registered entities, and trades groups familiar with IBR issues and reliability risks. Among other activities, the IRPTF has developed a variety of whitepapers and reliability guidelines.[45] For example, the Modeling and Studies Report documented the failure of industry to mitigate IBR-related momentary cessation, tripping, and modeling issues.[46] In March 2020, the IRPTF issued a white paper evaluating the applicability of certain Reliability Standards to IBRs and identifying seven Reliability Standards with potential gaps or areas for improvement.[47]

20. NERC formed the SPIDERWG to, among other things, identify potential gaps in the Reliability Standards and address IBR–DER modeling and performance.[48] For example, on December 30, 2019, the SPIDERWG submitted a standard authorization request proposing to address gaps in Reliability Standard MOD–032–1 (Data for Power System Modeling and Analysis) requirements for data collection for the purposes of modeling and interconnection-wide planning case models.[49] Based on the extensive record created by the IRPTF and SPIDERWG on the need for the Reliability Standards to address IBR impacts on the reliable operation of the Bulk-Power System, NERC initiated several standards projects [50] to consider discrete changes

(6) NERC and WECC, *Multiple Solar PV Disturbances in CAISO* (April 2022), *https://www.nerc.com/pa/rrm/ea/Documents/NERC_2021_California_Solar_PV_Disturbances_Report.pdf* (2021 Solar PV Disturbances Report) (covering four events: Victorville (June 24, 2021); Tumbleweed (July 4, 2021); Windhub (July 28, 2021); and Lytle Creek (August 26, 2021)); and

(7) NERC and Texas RE, *March 2022 Panhandle Wind Disturbance Report* (August 2022), *https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf* (Panhandle Report) (covering the Texas Panhandle event (March 22, 2022)).

[36] NERC, *Industry Recommendation: Loss of Solar Resources during Transmission Disturbances due to Inverter Settings* (June 2017), *https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20Loss%20of%20Solar%20Resources%20during%20Transmission%20Disturbance.pdf* (Loss of Solar Resources Alert I); NERC, *Industry Recommendation Loss of Solar Resources during Transmission Disturbances due to Inverter Settings—II* (May 2018), *https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC_Alert_Loss_of_Solar_Resources_during_Transmission_Disturbance-II_2018.pdf* (Loss of Solar Resources Alert II).

[37] *See IBR Performance Guideline;* NERC, *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources* (Sept. 2019), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf* (IBR Interconnection Requirements Guideline); NERC, *Reliability Guideline: Performance, Modeling, and Simulations of Bulk-Power System-Connected Battery Energy Storage Systems and Hybrid Power Plants* (Mar. 2021), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_BESS_Hybrid_Performance_Modeling_Studies_.pdf (BESS Performance Modeling Guideline).*

[38] The task force later became the IBR Performance Working Group in October 2020, and most recently became the IBR Performance Subcommittee in March 2022. For consistency, this NOPR uses ''IRPTF'' to refer to all three iterations.

[39] *See, e.g.,* NERC, *Technical Report, Bulk-Power System-Connected Inverter-Based Resource Modeling and Studies,* (May 2020), *https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/NERC-WECC_2020_IBR_Modeling_Report.pdf* (Modeling and Studies Report); NERC and WECC, *WECC Base Case Review: Inverter-Based Resources* (Aug. 2020), *https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/NERC-WECC_2020_IBR_Modeling_Report.pdf* (Western Interconnection (WI) Base Case IBR Review).

[40] NERC IBR Strategy, (July 2021), *https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/2022-2024%20RSDP%20FERC%20Filing.pdf.*

[41] Federal Energy Regulatory Commission, *Table of Cited NERC IBR Resources (RM22–12–000), https://www.ferc.gov/media/table-cited-nerc-ibr-resources-rm22-12-000.*

[42] NERC uses level 2 alerts to recommend specific actions to be taken by registered entities (*i.e.,* ''Recommendation to Industry''). A response from recipients, as defined in the alert, is required. NERC, *About Alerts* (2022), *https://www.nerc.com/pa/rrm/bpsa/Pages/About-Alerts.aspx.* NERC also uses level 1 alerts (*i.e.,* ''Industry Advisory'') to advise registered entities of issues or potential problems, which does not require a response. In addition, NERC uses level 3 alerts (*i.e.,* ''Essential Action'') to identify actions that registered entities are required to take because they are deemed to be ''essential'' to reliability.

[43] Loss of Solar Resources Alert I at 4–6 (noting that although the alert pertains directly to registered IBRs, the ''same potential susceptibility to frequency and voltage perturbations during transmission faults exist for all utility grade, and perhaps some larger commercial grade solar installations, regardless of the interconnection voltage.'').

[44] Loss of Solar Resources Alert II at 1–5 (finding again that ''[a]lthough this NERC Alert pertains specifically to [bulk electric system] solar PV resources, the same characteristics may exist for non-[bulk electric system] solar PV resources connected to the [Bulk-Power System] regardless of installed generating capacity or interconnection voltage.'' (footnote omitted)).

[45] *See* NERC, *Reliability Guidelines, Security Guidelines, Technical Reference Documents, and White Papers,* (2022), *https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx* (providing links to all IRPTF resources).

[46] Modeling and Studies Report at iv–v, 1–8.

[47] Specifically, the white paper identified Reliability Standards: (1) FAC–001–3; (2) FAC–002–2; (3) MOD–026–1; (4) MOD–027–1; (5) PRC–002–2; (6) TPL–001–4/-5; and (7) VAR–002–4.1. NERC, *IRPTF Review of NERC Reliability Standards White Paper,* 1, (Mar. 2020), *https://www.nerc.com/pa/Stand/Project202104ModificationstoPRC0022DL/Review_of_NERC_Reliability_Standards_White_Paper_062021.pdf* (Reliability Standards Review White Paper).

[48] NERC, *System Planning Impacts from DER Working Group (SPIDERWG),* (2022) *https://www.nerc.com/comm/RSTC/Pages/SPIDERWG.aspx.*

[49] NERC, *Standard Authorization Request,* Project 2020–01 Modifications to MOD–032–1 (Dec. 2021), *https://www.nerc.com/pa/Stand/Project202202ModificationstoTPL00151andMOD0321DL/2022-02_MOD-032%20SAR%20SPIDERWG_020122.pdf.*

[50] *See* NERC Rules of Procedure, app. 3A (Standard Processes Manual) (providing the process for developing, modifying, withdrawing, or retiring a Reliability Standard. One of the first steps in the process is initiating a standards authorization request, which is a form used to document the scope and benefit of a proposed standards drafting project).

to the Facilities Design, Connections and Maintenance (FAC), Modeling, Data and Analysis (MOD), Protection and Control (PRC), Transmission Planning (TPL), and Voltage and Reactive Control (VAR) Reliability Standards.[51]

21. Other NERC technical committees have also met to review recommendations of the Odessa Disturbance Report, including recommendations for Reliability Standards addressing, among other IBR-related issues: (1) ride through; (2) performance validation; (3) analysis and reporting for abnormal inverter options; (4) monitoring; and (5) inverter-specific performance requirements.[52]

22. Concurrently with this NOPR, we are also approving revisions to Reliability Standards FAC–001–3 (Facility Interconnection Requirements) and FAC–002–3 (Facility Interconnection Studies).[53] The revisions were responsive to IRPTF recommendations to modify the standards to: (1) clarify the registered entity responsible for determining which facility changes require study (a ''qualified change''); and (2) clarify that a generator owner should notify affected registered entities before making a qualified change. As a part of its petition, NERC included examples of qualified changes specific to IBRs, such as a change in inverter settings that may result in a difference in frequency or voltage support.[54]

23. In addition to NERC's efforts, there are voluntary industry standards and manufacturer certification efforts related to IBRs in place or underway, such as the Institute of Electrical and Electronics Engineers (IEEE) standard 2800–2020 [55] for transmission connected IBRs, and IEEE 1547–2018 [56] and Underwriters Laboratory (UL) standard UL 1741 [57] for IBR–DERs. These efforts may enhance the operating performance and control capabilities of IBRs; however, these efforts remain at relatively early stages, do not apply to all relevant IBRs, and require adoption by state or other regulatory authorities.[58] The proposed directives to NERC to develop new or modify existing Reliability Standards are intended to complement existing voluntary efforts underway and are not intended to supersede or interfere with these efforts.

III. The Need for Reform

A. Recent Events Show IBR-Related Adverse Reliability Impacts on the Bulk-Power System

24. A number of events have demonstrated the challenges to transmission planning and operations of the Bulk-Power System posed by gaps in the Reliability Standards specific to IBRs in the areas of: (1) IBR data sharing; (2) IBR model validation; (3) IBR planning and operational studies; and (4) registered IBR performance requirements.

25. The first documented large-scale disturbance event related to IBRs occurred in August of 2016 during the Blue Cut Fire event in California. Until this event, the potential for IBRs to affect the reliability of the Bulk-Power System by tripping or momentarily ceasing during faults was unknown.[59] A NERC/WECC joint task force determined that a single 500 kV line-to-line fault caused the widespread loss of 1,200 MW of primarily solar PV IBRs, which adversely affected the balance of generation and load needed to maintain Interconnection frequency near a nominal value of 60 Hz.[60] The task force found that the solar PV generation loss was primarily due to the unexpected tripping and unanticipated momentary cessation of IBRs.[61] The report indicated that planning studies incorrectly predicted that IBRs would ride through the disturbance and would provide power during the event. Once aware of the potential for IBRs to trip or enter momentary cessation in response to faults, Southern California Edison (SoCal Edison) and the California Independent System Operator Corporation (CAISO) reviewed the supervisory control and data acquisition (SCADA) data from SoCal Edison energy management system and discovered that this was not an isolated incident.[62]

26. Despite NERC's efforts to date, events involving registered IBRs, unregistered IBRs, and IBR–DERs have continued to occur in areas of the country with large penetrations of IBRs.[63] Noting the continuing need to address IBR concerns, the NERC Board of Trustees has stated that ''the risk of unreliable performance from [Bulk-

[51] *See* NERC, Informational Filing of Reliability Standards Development Plan 2022–2024, Docket No. RM05–17–000, et al., attach. A (*Reliability Standards Development Plan 2022–2024*), 3–4 (filed Nov. 30, 2021) (NERC 2022–2024 Reliability Standards Development Plan). However, several of these projects lack IBR-specific considerations or reporting requirements (*e.g.,* MOD–026–1, MOD–027–1, and PRC–002–2), lack requirements to assess IBR aggregate impacts (*e.g.,* VAR–002–4.1), or are identified in the Reliability Standards development plan as ''low priority.'' *See also* NERC, *IBR Strategy, https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf* (providing a milestone plan of proposed SARs, reliability guidelines, and whitepapers).

[52] NERC, *Odessa Disturbance Follow-up White Paper,* 3–8 (Oct. 2021), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Odessa_Disturbance_Follow-Up.pdf* (Odessa Disturbance White Paper).

[53] *See North American Electric Reliability Corporation,* 181 FERC ¶ 61,126 (2022).

[54] NERC, Petition for Approval of Proposed Reliability Standards FAC–001–4 and FAC–002–4, Docket No. RD22–5–000, at 9–13 (filed June 14, 2022) (including examples of IBR-related qualified changes: (1) a change of 10% or more in nameplate capacity of the IBR; and (2) a change in the IBR's control settings that cause a difference in (a) frequency or voltage support or (b) when the IBR stops injecting power into the transmission system).

[55] IEEE *Standard for Interconnection and Interoperability of Inverter-Based Resources (IBR) Interconnecting with Associated Transmission Electric Power Systems* (IEEE 2800–2022), *https://standards.ieee.org/ieee/2800/10453/* (explaining that 2800–2020 standard establishes ''[u]niform technical minimum requirements for the interconnection, capability, and lifetime performance of [IBRs] interconnecting with transmission and sub-transmission systems . . . [and includes] . . . performance requirements for reliable integration of [IBRs] into the [B]ulk [P]ower [S]ystem.'').

[56] IEEE, *Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces* (IEEE 1547–2018), *https://sagroups.ieee.org/scc21/standards/1547rev/.* The IEEE 1547–2018 and more recent 2020 amendment of this standard enhance operating performance and control capabilities of IBR–DER. For example, future IBR–DER will be equipped with the capability to ride through voltage and frequency fluctuation in support of the reliable operation of Bulk-Power System.

[57] UL Standard 1741 Edition 3, *Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources Scope, https://www.shopulstandards.com/ProductDetail.aspx?UniqueKey=40673.*

[58] While the IEEE–2800–2020 was approved in September 2022, it has yet to be adopted by any transmission entity. For IEEE–1547, states have made varied progress in adopting the IBR–DER. Adoption of IEEE Standard 1547™-2018. Further, *IEEE 1547–2018* inverter products are not expected to be generally available to the market until April 2023. IEEE, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, https://sagroups.ieee.org/scc21/standards/1547rev/.*

[59] Blue Cut Fire Event Report at 15–16.

[60] *Id.* at 1.

[61] *Id.* at 9 (identifying momentary cessation as a major cause for the loss of IBRs when voltages rose above 1.1 per unit or decreased below 0.9 per unit. NERC also identified IBRs that tripped due to erroneous frequency calculations and concluded that a more accurate representation of the system frequency measurement should be used for inverter controls, and a minimum delay for frequency detection and/or filtering should be implemented. NERC reported that the Blue Cut fire IBR erroneous frequency calculation issue was successfully mitigated).

[62] SoCal Edison/CAISO identified seven other instances of solar PV IBRs either tripping or entering momentary cessation. *Id.* at 3. *See also* Modeling and Studies Report at 3–4 (explaining that SoCal Edison and CAISO attempted to collect updated generation dynamic models from generator owners and discussing their challenges in obtaining the data).

[63] Since the first Blue Cut Fire event in August 2016, there have been at least 11 additional events throughout the last six years, including the most recently reported event in March 2022. NERC, *Major Event Analysis Reports, https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx, see supra* note 12 (listing the IBR-related events).

Power System]-connected inverter-based resources remains high'' and that NERC and the Regional Entities ''remain[] concerned with [Bulk-Power System] performance, modeling, planning and study approaches, and is urging immediate industry action.'' [64] As the resource mix trends towards higher penetrations of IBRs, the need to reliably integrate these resources into the Bulk-Power System is expected to grow.[65] Although groups such as IEEE and entities like CAISO have attempted to address these issues at the state, local, or individual entity level, the continuing events across the Bulk-Power System and the risks that they pose to its reliable operation underscore the need for mandatory Reliability Standards to address these issues on a nationwide basis.

B. Reliability Standards Do Not Adequately Address IBR Reliability Risks

1. Data Sharing

27. The Reliability Standards do not ensure that planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities receive accurate and complete data on the location, capacity, telemetry, steady-state, dynamic and short circuit modeling information, control settings, ramp rates, equipment status, disturbance analysis data, and other information about IBRs (collectively, IBR data). IBR data is necessary to properly plan, operate, and analyze performance on the Bulk-Power System.[66] As evidenced by the Modeling and Studies Report, the Reliability Standards do not ensure that IBR generator owners and operators consistently share IBR data, as at least a portion of the information that is shared is inaccurate or incomplete.[67] For example, in the Modeling and Studies Report, the IRPTF found that Reliability Standard MOD–032–1 ''does not prescribe the details that the modeling requirements must cover; rather, the standard requirements leave the level of detail and data formats up to each TP [transmission planner] and PC [planning coordinator] to define.'' Further, the IRPTF found that many of the dynamic models submitted in response to an IBR-related NERC Alert ''that were intended to represent the existing settings and controls currently installed in the field either did not match the data provided by the [generator owner] for actual settings or did not meet the [transmission planner and planning coordinator] requirements for model performance, (*i.e.,* incorrect models used, incorrect parameters, or inability of model to initialize).'' [68]

28. Without accurate and complete IBR data, planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities are not able to develop accurate system models that account for the behavior of IBRs on their system, nor are they able to facilitate the analysis of Bulk-Power System disturbances.[69]

a. Registered IBR Data Sharing

29. The Reliability Standards do not ensure that transmission planners and operators receive modeling data and parameters from all bulk electric system generation resources necessary to create and maintain valid individual registered IBR models used to perform steady-state, dynamic, and short circuit studies. While Reliability Standard MOD–032–1(Data for Power System Modeling and Analysis), Requirement R2, requires generator owners to submit modeling data and parameters to their transmission planners and planning coordinators, it does not require generator owners to submit registered IBR-specific modeling data and parameters, such as control settings for momentary cessation and ramp rates, necessary for modeling steady state and dynamic registered IBR performance for purposes of planning the Bulk-Power System.[70] Similarly, Reliability Standard TOP–003–4 (Operational Reliability Data) does not require generator owners to submit registered IBR-specific modeling data and parameters transmission operators or balancing authorities, such as control settings for momentary cessation and ramp rates, necessary for modeling steady state and dynamic registered IBR performance for purposes of operating the Bulk-Power System.

b. Unregistered IBR and IBR–DER Data Sharing

30. The Reliability Standards do not ensure that transmission planners and operators receive modeling data and parameters regarding unregistered IBRs and IBR–DERs that, individually or in the aggregate, are capable of adversely affecting the reliable operation of the Bulk-Power System. As shown by various reports and guidelines,[71] planners and operators do not currently have the data to accurately model the behavior of unregistered IBRs as well as IBR–DERs in the aggregate for steady-state, dynamic, and short circuit studies.

c. Disturbance Monitoring Data Sharing

31. The Reliability Standards do not ensure that transmission planners and operators receive disturbance

[64] NERC, *Members Representatives Committee Agenda Package,* 2 (May 2022), *https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Policy-Input-Package-May-2022-PUBLIC-POSTING.pdf.*

[65] *See* Reliability Standards Review White Paper at 1 (finding that the ''electric industry is still experiencing unprecedented growth in the use of inverters as part of the bulk power system and growth is possibly creating new circumstances where current standards may not be sufficiently addressing those needs.'').

[66] Loss of Solar Resources Alert II at 7–8 (describing examples of planning and operational IBR data) and Odessa Disturbance Report at 20–21; *see generally* WI Base Case IBR Review, NERC, *Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies,* (Sept. 2020) (IBR–DER Data Collection Guideline).

[67] *See* Modeling and Studies Report at 33 (finding that a ''significant number of inverter-based resources, particularly solar PV resources, have submitted [root-mean-square] positive sequence dynamic models for the interconnection-wide case creation process (*i.e.,* MOD–032–1) that do not accurately represent the control settings programmed into the inverters installed in the field.''). *See also* Western Interconnection (WI) Base Case IBR Review at 27 (describing comments from transmission planners and planning coordinators relaying concerns regarding generator owners' lack of timely responses (or any response in many cases) regarding modeling-related issues on the use of generic manufacturer-supplied data, and failure to update models consistent with Reliability Standard MOD–032–1).

[68] Modeling and Studies Report at 33.

[69] *E.g.,* Commission Staff, *Distributed Energy Resources Technical Considerations for the Bulk Power System Staff Report,* Docket No. AD18–10–000 (filed Feb. 15, 2018) (Commission Staff IBR–DER Reliability Report); Modeling and Studies Report at 33 (recommending that generator owners, for both registered and unregistered IBRs, ''should submit updated models to the [transmission planners and planning coordinators] as quickly as possible to accurately reflect the large disturbance behavior of [Bulk-Power System]-connected solar PV resources in the interconnection-wide base cases used for planning assessments.'').

[70] *See* Modeling and Studies Report at 35 (stating that Reliability Standard MOD–032–1 ''does not prescribe the details that the modeling requirements must cover; rather, the standard requirements leave the level of detail and data formats up to each [transmission planner] and [planning coordinator] to define.'' (footnote omitted)).

[71] *See, e.g.,* Commission Staff IBR–DER Reliability Report at 11–13 (explaining that absent adequate data, many Bulk-Power System models and operating tools will not fully represent the effects of IBR–DERs in aggregate. The report also noted the lack of a formal process to provide static IBR–DER data to Bulk-Power System operators and planners as well as the limited visibility that operators and planners have into IBR–DER telemetry data); *see also* IBR–DER Data Collection Guideline at 2 (recommending that transmission planners and planning coordinators update their data reporting requirements for Reliability Standard MOD–032–1, Requirement R1 to explicitly describe the requirements for aggregate IBR–DER data in a manner that is clear and consistent with their modeling practices. The guideline also recommended that transmission planners and planning coordinators establish modeling data requirements for steady-state IBR–DERs in aggregate and coordinate with their distribution providers to develop these requirements).

monitoring data regarding all generation resources capable of having a material impact on the reliable operation of the Bulk-Power System, including IBRs, to adequately assess disturbance events (*e.g.,* a fault on the line, a generator tripped off-line) and their behavior during those events. Without adequate monitoring capability, the disturbance analysis data for a system event is not comprehensive enough to effectively determine the causes of the system event.[72] Further, the absence of adequate monitoring capability leads to the potential for unreliable operation of resources due to the inability to effectively gather disturbance analysis data and develop mitigation strategies for abnormal resource performance during disturbance events.

32. Limitations on the availability of event data have hampered efforts by NERC and industry to determine the causes of various events since 2016, explained in more detail below. In many instances, data was limited and disturbance monitoring equipment was absent because registered IBRs generally do not fall within the thresholds of the current Reliability Standard PRC–002–2 (Disturbance Monitoring and Reporting Requirements) Attachment 1 methodology requirements for equipment installation given that they often interconnect at lower voltages and are typically smaller compared to synchronous generators.[73] While Reliability Standard PRC–002–2 requires the installation of disturbance monitoring equipment at certain key nodes (*e.g.,* stability limited interfaces), and such limited placements were adequate to provide the data necessary to analyze major system events in the past, they are not sufficient to analyze the distributed system events that have become more common since 2016.[74]

2. IBR and IBR–DER Data and Model Validation

33. IBR-specific modeling data and parameters are necessary to ensure that the registered entities responsible for planning and operating the Bulk-Power System can validate both the individual registered IBR and unregistered IBR data as well as IBR–DER data in the aggregate by comparing the provided data and resulting models with actual performance and behavior.[75] Therefore, even if the Reliability Standards did ensure planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities receive registered IBR modeling data from registered IBR generator owners and operators, the Reliability Standards would still need to include unregistered IBR modeling data and parameters and IBR–DER aggregate modeling data and parameters to ensure reliability. The bulk electric system definition, which delineates the entities required to comply with the Reliability Standards, does not include unregistered IBRs or IBR–DERs. Therefore, the current Reliability Standards do not address the provision of either unregistered IBR or IBR–DER aggregate modeling data and parameters. Further, the Reliability Standards do not include IBR-specific modeling data and parameters (*e.g.,* performance and control settings). As a result, the planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities need to coordinate with: (1) registered IBR generator owners and operators, (2) transmission owners that have unregistered IBRs connected to their systems, (3) and the distribution providers that have IBR–DERs to obtain IBR specific modeling data and parameters so that the transmission planners and operators can validate the accuracy of such data to create meaningful models of steady-state and dynamic registered IBR, unregistered IBR, and aggregate IBR–DER performance.[76]

34. System planners and operators need accurate planning, operational, and interconnection-wide models to ensure reliable operation of the system. Planners and operators use electrical component models to build the generation, transmission, and distribution facility models that form the planning and operational area models, and these area models are combined with the models of their neighboring footprints to form the interconnection-wide models. Each of the planning, operational, and interconnection-wide models consist separately of steady state, dynamic, and short circuit models.

35. Without planning, operational, and interconnection-wide models that accurately reflect the resource (*e.g.,* generators and loads) behavior in steady state and dynamic conditions; otherwise, planners and operators are unable to adequately predict resources' behaviors, including momentary cessation from both individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate and subsequent impacts

[72] 2021 Solar PV Disturbances Report at 13. The report explains that the ''analysis team had significant difficulty gathering useful information for root cause analysis at multiple facilities . . . [and] this led to an abnormally large number of 'unknown' causes of power reduction for the plants analyzed.''

[73] Reliability Standard PRC–002–2, Attachment 1 includes a methodology for selecting which buses require sequence of events recording and fault recording data—IBRs do not meet the threshold for this methodology.

[74] *See, e.g.,* Angeles Forest and Palmdale Roost Events Report at 23 (explaining that the lack of data visibility and poor data quality continue to be a concern for comprehensive event analysis after large Bulk-Power System disturbances, as well as how the quality of event reporting is negatively affected by data acquisition resolution issues as a lack of high speed data captured at the IBR controller hinders a complete analysis of IBR behavior in response to Bulk-Power System fault events); San Fernando Disturbance Report at 7 (explaining that many facilities have data archiving systems that only record, store, and retrieve information with a one-minute resolution (or a five-minute resolution in some cases) and that no facilities recorded electrical quantities with sufficient resolution to observe their on-fault behavior, limiting the ability to perform a more detailed analysis of the event.); Odessa Disturbance Report at 11 (indicating some improved monitoring data, but noting the monitoring capability at solar PV facilities is not comprehensive enough to effectively perform root cause analysis and is leading to unreliable operation of these resources due to the inability to effectively develop mitigations for abnormal performance). *See generally* Odessa Disturbance White Paper; NERC, *San Fernando Disturbance Follow-Up NERC Inverter-Based Resource Performance Working Group White Paper,* (June 2021), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/IRPWG_San_Fernando_Disturbance_Follow-Up_Paper%20(003).pdf* (San Fernando Disturbance White Paper).

[75] Modeling and Studies Report at 37 (recommending revising Reliability Standards MOD–026–1 (Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions) and MOD–027–1 (Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions) to ''ensure that large disturbance behavior of [IBRs] is verified.''). In addition, the task force recommended that transmission planners and planning coordinators ''should be required to verify the appropriateness of all dynamic model parameters to ensure suitability of these parameters to match actual performance for all operating conditions.'' *Id. See also* WI Base Case IBR Review at v (recommending that IBR owners ensure that all data fields are reported correctly, that transmission planners and planning coordinators ''should verify that the data fields are submitted correctly,'' and that the Regional Entity ''should ensure that data quality checks are being performed on all incoming data from [transmission planners] and [planning coordinators] for their areas.'').

[76] Static or steady-state models represent electrical component state variables as constant with respect to the time variable of the simulation. Steady-state models are used to represent a single snapshot of balanced system conditions as observed during normal Bulk-Power System operations and serve as a basis of subsequent time-variant technical studies. Dynamic models represent electrical component state variables that vary with time depending on the course of the simulation. Dynamic models are built upon steady-state models and may be validated to ensure they adequately reflect actual historic performance and/or field-testing data. Dynamic models are used by the industry to evaluate resource (*i.e.,* generation and load) performance during simulated events and event investigations.

on the Bulk-Power System.[77] Accordingly, to be able to adequately predict resources' behaviors, planners and operators must validate and update resource models by comparing the provided data and resulting models against actual operational behavior.[78] When accuracy and validation of models are combined, these planning, operational, and interconnection-wide models enable planners and operators to perform valid planning, operational, and interconnection-wide studies.

a. Approved Component Models

36. The starting points for an accurate planning, operational, and interconnection-wide model are the steady state, dynamic, and short circuit models of the elements that make up generation, transmission, and distribution facilities. To this end, NERC has worked with its stakeholders to develop, validate, and maintain a library of standardized approved component models (*e.g.,* generator elements) and parameters for powerflow and dynamic cases.[79] NERC's approved component model list is a collection of generic industry steady-state and dynamic models (*e.g.,* excitor, governor, load, etc.) that when combined accurately reflect the steady-state and dynamic performance of a resource.[80] Despite these efforts, some resource owners still provide modeling data that is based on a proprietary model rather than an approved industry-vetted model.[81] The use of proprietary models in interconnection-wide models can be problematic because their internal model components cannot be viewed or modified, and thus produce outputs that cannot be explained or verified.[82] Without using approved generator models that accurately reflect the generator behavior in steady state and dynamic conditions, planners and operators are unable to adequately predict IBR behavior and subsequent impact on the Bulk-Power System.[83] The Reliability Standards do not require the use of NERC's approved component models; instead, models are referred to generally in Reliability Standard MOD–032–1 Attachment 1.[84]

b. IBR Plant Dynamic Model Performance Verification

37. Once each generator provides a NERC and industry-approved generator model, the model performance must be verified by real-world data.[85] The currently effective Reliability Standards MOD–026–1 [86] and MOD–027–1 [87] require the generator owner to verify models and data for specific components of synchronous resources (*e.g.,* generator excitation control systems, plant volt/var control functions, turbine/governor and load controls, and active power/frequency controls), but they do not require a generator owner to provide verified models and data for IBR-specific controls (*e.g.,* power plant central controller functions and protection system settings). Further, the Reliability Standards neither require verified dynamic models from the transmission owner for unregistered IBRs nor require verified IBR–DER dynamic models in the aggregate from distribution providers.

38. Transmission planners and operators need dynamic models (*i.e.,* models of equipment that reflect the equipment's behavior during changing grid conditions and disturbances) that accurately represent the dynamic performance of all generation resources, including momentary cessation when applicable. As discussed in several NERC analyses,[88] current IBR dynamic models do not accurately represent disturbance behavior due to model deficiencies and because certain key parameters that govern large disturbance response are incorrect; thus, planners are not able to rely on these IBR dynamic models. Unless IBR models are verified to ensure that the models accurately reflect IBR performance during testing or actual events, planners' and system operators' unverified models may indicate that the IBRs will behave reliably when studied in planning and operational analyses, even if ride through operation modes such as momentary cessation persist in actual operations, as observed during

[77] *See* IBR Interconnection Requirements Guideline at 24 (stating that a systemic modeling issue was uncovered regarding the accuracy of the inverter-based resource dynamic models submitted in the interconnection-wide base cases following the issuance of the NERC Alert related to the Canyon 2 Fire disturbance).

[78] *See* Modeling and Studies Report at 35 (explaining that assessments on the accuracy or reasonableness of modeling parameter values are not typically performed and standardized validity testing for dynamic models of newer generation inverter-based resources is not readily available to planners; therefore, contributing to inaccuracies in the interconnection-wide base cases).

[79] NERC Libraries of Standardized Powerflow Parameters and Standardized Dynamics Models version 1 (Oct. 2015), *https://www.nerc.com/comm/PC/Model%20Validation%20Working%20Group%20MVWG%202013/NERC%20Standardized%20Component%20Model%20Manual.pdf* (NERC Standardized Powerflow Parameters and Dynamics Models).

[80] The models are specific to the power flow software. NERC communicates the approved models list by issuing modeling notifications and guidelines. NERC annually assesses the interconnection-wide case quality and publishes a report to help entities responsible for complying with Reliability Standard MOD–032–1 to resolve model issues and improve the cases. *See* NERC, *Reliability Assessment and Performance Analysis Department Modeling Assessments, https://www.nerc.com/pa/RAPA/ModelAssessment/Pages/default.aspx.*

[81] NERC Standardized Powerflow Parameters and Dynamics Models at 1 (explaining that ''[s]ome of the model structures have information that is considered to be proprietary or confidential, which impedes the free flow of information necessary for interconnection-wide power system analysis and model validation.'') *See also* NERC, *Events Analysis Modeling Notification Recommended Practices for Modeling Momentary Cessation Initial Distribution,* n.4 (Feb. 2018), *https://www.nerc.com/comm/PC/NERCModelingNotifications/Modeling_Notification_-_Modeling_Momentary_Cessation_-_2018-02-27.pdf* (explaining that more detailed vendor-specific models may be used for local planning studies; however, they are generally not allowed or recommended for the interconnection-wide cases).

[82] *See, e.g.,* Electric Power Research Institute, *Model User Guide for Generic Renewable Energy System,* 2 (June 2015), *https://www.epri.com/research/products/000000003002006525* (explaining that the ''models presented here were developed primarily for the purpose of general public use and benefit and to eliminate the long standing issues around many vendor-specific models being proprietary and thus neither publicly available nor easily disseminated among the many stakeholders. Furthermore, using multiple user-defined non-standard models within large interconnection studies, in many cases, presented huge challenges and problems with effectively and efficiently running the simulations.'').

[83] NERC Standardized Powerflow Parameters and Dynamics Models (explaining that there is a growing need for accurate interconnection-wide powerflow and dynamics simulations that analyze phenomena such as: frequency response, inter-area oscillations, and interactions between the growing numbers of wide-area control and protections systems).

[84] Reliability Standard MOD–032–1, Attachment 1 (explaining that if a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables).

[85] NERC Standardized Powerflow Parameters and Dynamics Models at 1 (explaining that the NERC Modeling Working Group was tasked to develop, validate, and maintain a library of standardized component models and parameters for powerflow and dynamics cases. The standardized models in these libraries have documentation describing their model structure, parameters, and operation. This information has been vetted by the industry and thus deemed appropriate for widespread use in interconnection-wide analysis.).

[86] Reliability Standard MOD–026–1 (Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions).

[87] Reliability Standard MOD–027–1 (Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions).

[88] WI Base Case IBR Review at 18, 25 (finding that the models are not parameterized with as-built settings and that verification of dynamic models is not capturing errors); *see also* Modeling and Studies Report at 34 (finding that a significant number of generator owners submitted data in response to the Loss of Solar Resources Alert II ''indicating that they could eliminate the use of [momentary cessation] for existing resources; however, either no model of proposed changes was provided, or the provided model did not meet [transmission planner] and [planning coordinator] requirements for model performance.'').

the Blue Cut Fire and Canyon 2 Fire events. Additionally, the 2017 NERC DER Report explained that accurate IBR–DER dynamic models are needed where ''[IBR-]DERs are expected to have a significant impact on the modeling results.'' [89]

39. NERC has issued multiple recommendations for: (1) generator owners of IBRs to ensure that their dynamic models accurately represent the behavior of the actual installed equipment; [90] (2) transmission planners and planning coordinators to work with generator owners and operators of IBRs connected to their system to ensure that the dynamic models correctly represent the large disturbance behavior of the actual installed equipment; [91] and (3) transmission planners and planning coordinators to develop updated dynamic models of their systems that accurately represent momentary cessation and to study the impacts of IBRs on the Bulk-Power System.[92]

c. Validating and Updating System Models

40. Transmission planners and operators must validate and update system models by comparing the provided data and resulting system models against actual system operational behavior. While Reliability Standard MOD–033–2 requires data validation of the interconnection-wide system model, [93] the Reliability Standards lack clarity as to whether models of registered IBRs, unregistered IBRs, and IBR–DERs in the aggregate are required to represent the real-world behavior of the equipment installed in the field for interconnection-wide disturbances that have demonstrated common mode failures of IBRs.[94]

41. In addition, Reliability Standard MOD–032–1 lacks clarity on whether generator owners are required to communicate to planners and operators if there are any changes to registered IBRs, including settings, configurations, and ratings. Additionally, transmission owners are not required to communicate to planners and operators if there are any changes to unregistered IBRs for modeling, including settings, configurations, and ratings. Similarly, distribution providers are not required to communicate to planners and operators if there are any changes to IBR–DERs in the aggregate for modeling, including settings, configurations, and ratings. While Reliability Standards MOD–032–1 and MOD–033–2 have iterative updating and validation processes, Reliability Standard MOD–032–1 lacks IBR-specific modeling data and parameters and Reliability Standard MOD–033–2 does not contemplate the technology-specific performance characteristics of registered IBRs, unregistered IBRs, and IBR–DERs. As NERC explained in its petition for approval of the proposed Reliability Standards MOD–032–1 and MOD–033–2, the lack of generator model verification can result in ''the use of inaccurate models [that] could result in grid underinvestment, unsafe operating conditions, and ultimately widespread power outages.'' [95]

42. In the November 2020 San Fernando Disturbance Report, NERC and WECC found that the previously identified modeling issues in the interconnection-wide planning base cases and modeling challenges continued to be an issue.[96] The San Fernando Disturbance Report again recommended that generator owners and generator operators take steps to ensure communication of changes to various settings, topologies, and ratings to their relevant transmission planner, planning coordinator, balancing authority, and reliability coordinator.[97]

d. Lack of Coordination When Creating and Updating Planning, Operational, and Interconnection-Wide Models

43. Planners and operators need to coordinate planning, operational, and interconnection-wide models so that they represent all generation resources—including registered IBRs, unregistered IBRs, IBR–DERs in the aggregate and synchronous generation—and load. When coordinated properly, these sets of models ensure enough detail for planners and operators to perform valid planning, operational, and interconnection-wide studies.

44. Reliability Standard MOD–032–1 Requirement R4 requires planning coordinators to make available models for their planning areas to the ERO or its designee [98] to support creation of interconnection-wide cases.[99] Two reliability gaps lead to interconnection-wide cases that do not reflect the large disturbance behavior that NERC identified in its analyses of IBR disturbance events. The first gap is the use of incorrect and unvalidated registered IBR, unregistered IBR, and IBR–DER models (discussed above) that do not accurately represent performance and behavior of both individual and

[89] NERC, *Distributed Energy Resources: Connection Modeling and Reliability Considerations,* 7 (Feb. 2017), *https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf (*NERC DER Report) at 6 (explaining that ''[a]n assessment of the expected impact will have to be scenario-based, and the time horizon of interest may vary between study types. For long-term planning studies, expected DER deployment levels looking 5–10 years ahead may reasonably be considered.''). The NERC DER Report also noted that modeling the modern Bulk-Power System ''with a detailed representation of a large number of [IBR-]DER[s] and distribution feeders can increase the complexity, dimension, and handling of the system models beyond practical limits in terms of computational time, operability, and data availability.'' *Id.*

[90] *See, e.g.,* Loss of Solar Resources Alert II at 2 (generators should ''[e]nsure that the dynamic model(s) being used accurately represent the dynamic performance of the solar facilities.'' The generator owners should ''update the dynamic model(s) to accurately represent momentary cessation and provide the model(s) to the Transmission Planner and Planning Coordinator (to support . . . Reliability Standard TPL–001–4 studies) and to the Reliability Coordinator, Transmission Operator, and Balancing Authority (in accordance with . . . Reliability Standards TOP–003–3 and IRO–010–2).''); *see also* WI Base Case IBR Review at 18, 25 (recommending that the IBR generator owners update their generic models as soon as possible).

[91] *See, e.g.,* Modeling and Studies Report at 33 (recommending that ''[Generator owners] should submit updated models to the [transmission planners] and [planning coordinators] as quickly as possible to accurately reflect the large disturbance behavior of [Bulk-Power System]-connected solar PV resources in the interconnection-wide base cases used for planning assessments. This applies to [bulk electric system] resources as well as non-[bulk electric system] resources connected to the [Bulk-Power System].''). NERC further recommended that ''[transmission planners] and [planning coordinators] should proactively work with all [Bulk-Power System]-connected solar PV resources connected to their system to ensure that the dynamic models correctly represent the large disturbance behavior of the actual installed equipment. [Generator owners] should verify the dynamic model parameters with actual equipment and control settings. These activities should occur on a regular basis.'' *Id.*

[92] *Id.* at 34; *see also* Loss of Solar Resources Alert II at 3.

[93] Reliability Standard MOD–033–2 (Steady State and Dynamic System Model Validation), Requirements R1, R2.

[94] NERC annually assesses the interconnection-wide case quality and publishes a report to help entities responsible for complying with Reliability Standard MOD–032 to resolve model issues and improve the cases. As NERC's 2021 Case Quality Metrics Assessment asserts, currently planners are neither able to develop accurate system models that account for the IBRs on their system, nor facilitate the analysis of Bulk-Power System disturbances. *See* NERC, *Case Quality Metrics Annual Interconnection-wide Model Assessment,* (Oct. 2021), *https://www.nerc.com/pa/RAPA/ModelAssessment/ModAssessments/2021_Case_Quality_Metrics_Assessment-FINAL.pdf.*

[95] NERC, Petition for Approval of Proposed Reliability Standards MOD–032–1 and MOD–033–1, Docket No. RD14–5–000, at 2, 9–10 (filed Feb. 25, 2014).

[96] San Fernando Disturbance Report at ix; Odessa Disturbance Report at 22–28, 29–31.

[97] San Fernando Disturbance Report at ix.

[98] *See* Reliability Standard MOD–032–1, Requirement R4.

[99] In this NOPR, the terms ''interconnection-wide case'' and ''interconnection-wide model'' are interchangeable. Both refer to a collection of electric power system models and requisite data developed to represent either a snapshot of the electric power system at a particular point of time (*e.g.,* year, season) or to represent the power system at a particular operating condition (*i.e.,* normal or abnormal).

aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate. Planners and operators incorporate incorrect and unvalidated IBR models within the footprint of the planner and operator area models. These registered IBR, unregistered IBR, and IBR–DER model inaccuracies from the planning and operation area models then propagate into the interconnection-wide cases.

45. Secondly, there is a coordination gap among registered entities that build and verify interconnection-wide cases. Reliability Standards MOD–032–1 and MOD–033–2 do not obligate the applicable entities to work collaboratively to create interconnection-wide cases that accurately reflect real-world interconnection-wide IBR performance and behavior.[100] In the Western Interconnection, for example, a single MOD–032–1 designee, WECC, collects a set of planning models from the planning authority and builds an interconnection-wide case on the behalf of the registered entities. Having a single MOD–032–1 designee helps in efficiently building an interconnection-wide case. However, the process does not contain requirements for the MOD–032–1 designee to coordinate and verify with MOD–033–2 functional entities (*e.g.,* the system operators) that the interconnection-wide cases reflect real-world IBR behaviors. For example, the Modeling and Studies Report indicates that the MOD–032–1 feedback loops are not being used to correct modeling issues.[101] Further, NERC's 2020 annual assessment of interconnection-wide case quality report explains that there is a need to compare the interconnection-wide models against actual measured system conditions and encourages planning coordinators to consider performing the comparison during MOD–033 evaluation, but such a comparison is not required by a standard.[102] The Reliability Standards should ensure registered entities coordinate to build interconnection-wide cases that reflect the large disturbance behavior of both individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate (*i.e.,* tripping offline or momentary cessation individually or in the aggregate in response to a single fault on a transmission or sub-transmission system).

46. NERC and WECC identified the impacts of these two reliability gaps in the WI Base Case IBR Review. Specifically, NERC and WECC found that IBR dynamic models used for interconnection-wide planning and operating studies do not properly represent the behavior of the equipment installed in the field, as current interconnection-wide cases contain many inaccurate and unverified IBR models, and many wind and solar PV IBRs are not represented.[103]

3. IBR and IBR–DER Planning and Operational Studies

47. The Reliability Standards do not ensure that planning and operational studies assess the performance and behavior (*e.g.,* IBRs tripping or entering momentary cessation individually or in the aggregate) of both individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate. Planning and operational studies must use validated registered IBR, unregistered IBR, and IBR–DER aggregate modeling and operational data (as discussed in above Section III.B.1. Data Sharing and Section III.B.2. IBR and IBR–DER Data and Model Validation) to ensure studies account for the actual behavior of registered IBRs, unregistered IBRs, and IBR–DERs in the aggregate. Planning and operational studies must assess the performance and behavior of individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate, during normal and contingency conditions for the reliable operation of the Bulk-Power System.

a. Planning Studies

48. Transmission planning (TPL) Reliability Standards are intended to ensure that the transmission system is planned and designed to meet an appropriate and specific set of reliability criteria. The TPL Reliability Standards, however, do not require planners to study in planning assessments the performance and behavior specific to both individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate, under normal operations and contingency event conditions. This reliability gap in planning assessments may lead to false expectations that system performance requirements are met and may inadvertently mask potential reliability risks in planning and operations. NERC's 2021 Battery Storage and Hybrid Plants Guideline further identifies reliability gaps in planning assessments related to newer technologies and provides recommendations to address some of the aforementioned concerns.[104] Nevertheless, as reliability guidelines are voluntary, the gap remains.

49. Reliability Standard TPL–001–4 (Transmission System Planning Performance Requirements) requires planning to ensure reliable operations over a broad spectrum of system conditions and following a wide range of probable contingencies.[105] The 2021 Solar PV Disturbances Report explains that ''many of the reliability issues observed in real-time [*e.g.,* solar PV resources tripping off line and momentary cessation] and identified in the numerous disturbance reports are not being captured in planning studies.'' [106] The Odessa Disturbance Report explains that IBR plants are ''abnormally responding to [Bulk-Power System] disturbance events and ultimately tripping themselves off-line'' and that these issues are not being

[100] Reliability Standard MOD–032–1 is applicable to the following entities: (1) balancing authority, (2) generator owner, (3) load serving entity, (4) planning authority/planning coordinator, (5) resource planner, (6) transmission owner, (7) transmission planner, and (8) transmission service provider.

[101] *See* Modeling and Studies Report at 27 (finding that ''[t]he feedback loops developed in MOD–032–1 are not being used by [transmission planners] and [planning coordinators] to correct modeling issues, nor are [transmission planners] and [planning coordinators] being proactive to address identified issues on a widespread basis.'').

[102] NERC, *Case Quality Metrics Annual Interconnection-Wide Model Assessment,* vii (Oct. 2020), *https://www.nerc.com/pa/RAPA/ModelAssessment/ModAssessments/2020_Case_Quality_Metrics_Assessment-FINAL_postpubs.pdf* (explaining that the report focuses solely on the case data quality of the individual component models comprising the base case and that validation of an interconnection-wide case or overall model performance requires comparison of the cases to actual measured system conditions and are not included in the report. Nevertheless, the report does encourage planning coordinators ''to consider these metrics in their MOD–033 evaluation and to also include metrics on case fidelity.'').

[103] WI Base Case IBR Review at 1–4.

[104] *See* BESS Performance Modeling Guideline, ix Recommendation S1 and S2 (explaining study process enhancements and expansion of study conditions are needed for both interconnection-wide and annual planning assessments to ensure that the variability and uncertainty of renewable energy resources (*e.g.,* registered IBRs, unregistered IBRs, and IBR–DERs in the aggregate) are reflected in planning analyses with appropriate dispatch conditions and under stressed operating conditions. NERC further explained that renewable energy resources have led to different operating conditions than were previously used in planning assessments and ''indicates that developing suitable and reasonable study assumptions will become a significant challenge for future planning analyses.'').

[105] Reliability Standard TPL–001–5.1 (Transmission System Planning Performance Requirements) was approved by the Commission to become effective on July 1, 2023. *See N. Am. Elec. Reliability Corp.,* Docket No. RD20–8–000 (June 10, 2020) (delegated letter order) (approving a NERC-proposed erratum to Reliability Standard TPL–001–5); *Transmission Planning Reliability Standard TPL–001–5,* Order No. 867, 85 FR 8155 (Feb. 13, 2020), 170 FERC ¶ 61,030 (2020) (approving Reliability Standard TPL–001–5).

[106] 2021 Solar PV Disturbances Report at 8 and 21.

properly detected by the models and studies conducted during annual planning assessments.[107] In addition, the Panhandle Report found that ''many [Bulk-Power System]-connected inverter-based resources (and distributed energy resources) will significantly reduce active power for depressed voltages'' that will change grid dynamics and should be accurately modeled in simulations and studied during planning assessments.[108]

50. The NERC DER Report found that many IBR–DERs are generally not visible to Bulk-Power System planners and stated that Bulk-Power System plans must account for this lack of visibility.[109] The report recommended that IBR–DERs be ''modeled in an aggregated and/or equivalent way to reflect their dynamic characteristics and steady-state output.'' [110] The report also found that planners face a challenge with respect to forecasting the adoption of IBR–DER types over long-term planning horizons with ''sufficient locational granularity for identifying and planning needed [Bulk-Power System] infrastructure upgrades.'' [111]

51. Similarly, in the WI Base Case IBR Review, NERC and WECC observed that IBR–DERs are not widely included in WECC base cases and noted that this could pose a ''risk for the creation of a reasonable starting case for entities neighboring those with notable [IBR–] DER penetrations.'' [112] NERC and WECC also observed that planners and operators do not have enough information about generators (including IBR information) to develop a complete and accurate base case.[113]

b. Operational Studies

52. Operators must perform various operational studies, including operational planning analyses, real-time monitoring, real-time assessments and other analyses that include all resources necessary to adequately assess the performance of the Bulk-Power System for normal and contingency conditions.[114] The Reliability Standards do not require operators to include the performance and behavior of both individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate (*e.g.,* IBRs tripping or entering momentary cessation individually or in the aggregate) in operational studies used to identify potential system operating limits and interconnection reliability operating limit exceedances and to identify any potential reliability risks related to instability, cascading, or uncontrolled separation. In addition, models of registered IBRs, unregistered IBRs, as well as models of IBR–DERs in the aggregate are generally not accurate (as discussed above), which invalidates the operational studies, as evidenced by numerous Bulk-Power System IBR disturbance events seen since 2016.[115] For example, in the FERC, NERC, and Regional Entity Joint Report on Real-time Assessments, ''[s]everal participants expressed concern that Contingencies may now change seasonally because of the decline in system inertia due to the growing number of Inverter-Based Resources in the generation mix. This placed a greater onus on the participant to conduct in-depth and up-to-date studies to ensure all stability Contingencies on its system are identified.'' [116]

53. In the Loss of Solar Resources Alert II, NERC recommended that reliability coordinators, transmission operators, and balancing authorities ''[t]rack, retain, and use the updated IBR dynamic model(s) . . . of existing resource performance that are supplied by the Generator Owners to perform assessments and system analyses to identify any potential reliability risks related to instability, cascading, or uncontrolled separation . . . .'' [117] In addition, the NERC DER Report explained that IBR–DERs do not follow a dispatch signal and are generally not visible to Bulk-Power System operators.[118] The NERC DER Report recommended that all components of the Bulk-Power System, including IBR–DERs, be modeled either directly or in aggregate, with sufficient fidelity to enable dynamic and steady-state models to provide meaningful and accurate simulations of actual system performance.[119]

4. IBR Performance

54. Essential reliability services, such as frequency and voltage support, serve as the basis for reliably operating the Bulk-Power System. Without the availability of essential reliability services, the system would experience instability, voltage collapse, or uncontrolled separation.[120] NERC's Essential Reliability Services Concept Paper initially identified two essential reliability services building blocks—voltage support and frequency support.[121] Some components of these services are provided automatically by synchronous generation due to their physical and mechanical properties. By contrast, IBRs must be configured and programmed to provide these services, and the Reliability Standards do not require registered IBRs to provide such services.

55. The Commission previously revised the *pro forma* Large Generator Interconnection Agreement and the *pro forma* Small Generator Interconnection Agreement to require newly interconnecting generating facilities to address certain issues related to essential reliability services. In Order No. 827, the Commission required all newly interconnecting non-synchronous generating facilities to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation as a condition of interconnection unless the transmission provider establishes a different power factor range, eliminating an earlier exemption for wind generation.[122] In Order No. 828, the Commission required newly interconnecting small generating facilities to have the capability to ''ride through abnormal frequency and voltage events and not disconnect during such events.'' [123] Finally, in Order No. 842,

[107] Odessa Disturbance Report at 43.

[108] Panhandle Report at 8.

[109] NERC DER Report at 3.

[110] *Id.* at 9.

[111] *Id.* at 35.

[112] WI Base Case IBR Review at 2.

[113] *Id.* at 1–4.

[114] *See* Reliability Standard TOP–001–5 (Transmission Operations), Requirements R10, R11, R13; Reliability Standard TOP–002–4 (Operations Planning), Requirements R1, R4; Reliability Standard IRO–008–2 (Reliability Coordinator Operational Analyses and Real-time Assessments), Requirements R1, R4; Reliability Standard IRO–002–7 (Reliability Coordination—Monitoring and Analysis), Requirement R5.

[115] *See* Modeling and Studies Report at iv (finding that ''Many of the dynamic models that were supplied by [generator owners] as part of the NERC Alert process had modeling errors or inaccuracies and were unusable to the [transmission planner] and [planning coordinator].''); *see also* NERC DER Report at vi (expressing that ''Today, the effect of aggregated [IBR-]DER is not fully represented in [Bulk-Power System] models and operating tools.'').

[116] FERC, NERC, Regional Entities, *Joint Report on Real-time Assessments,* 13–14 (July 2021), *https://www.ferc.gov/media/ferc-and-ero-enterprise-joint-report-real-time-assessments.*

[117] Loss of Solar Resources Alert II at 4–5.

[118] NERC DER Report at 3; *see also* IBR Performance Guideline at 65.

[119] NERC DER Report at iv, 9.

[120] Essential Reliability Services Concept Paper at iii.

[121] *Id.*

[122] *Reactive Power Requirements for Non-Synchronous Generation,* Order No. 827, 81 FR 40793 (June 23, 2016), 155 FERC ¶ 61,277, at PP 1–2 (2016).

[123] *Requirements for Frequency & Voltage Ride Through Capability of Small Generating Facilities,* Order No. 828, 81 FR 50290 (Aug. 1, 2016), 156 FERC ¶ 61,062, at P 1 (2016). The Commission went on to explain that it ''continues to affirm that this Final Rule is not intended to interfere with state interconnection procedures or agreements in any way. The *pro forma* SGIA applies only to interconnections made subject to a jurisdictional open access transmission tariff (OATT) for the

Continued

the Commission required newly interconnecting generating facilities ''to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection.'' [124]

a. Frequency Ride Through

56. The Reliability Standards do not account for the difference between registered IBRs' and synchronous facilities' responses during normal and contingency conditions. IBR technology is different than synchronous generation technologies. For instance, IBR ride through capability must be configured and programmed for IBRs to be able to ride through frequency disturbances. Synchronous resources will automatically ride through a disturbance because they are synchronized (*i.e.,* connected at identical speeds) to the electric power system and physically linked to support the system frequency during frequency fluctuations by continuing to produce real and reactive power. The frequency of an interconnection depends on the instantaneous balance between load and generation resources to which all resources must contribute during both normal and contingency conditions. This requires generation resources to remain connected to the grid and continue to support grid frequency (*i.e.,* ride through) for either loss of generation (underfrequency) or loss of load (overfrequency) related frequency deviations.

57. Reliability Standard PRC–024–3 (Frequency and Voltage Protection Settings for Generating Resources) does not include frequency ride through performance requirements that address the unique protection and control functions of IBRs. In particular, the Reliability Standard PRC–024–3 requirement for specific relay protection frequency settings does not address momentary cessation. As a result, registered IBRs are not required to continually produce real power and support frequency inside the ''no trip zone'' during a frequency excursion.[125]

58. In the Blue Cut Fire Event Report, NERC and WECC found that inverters that ''trip instantaneously based on near instantaneous frequency measurements are susceptible to erroneous tripping during transients generated by faults'' on the Bulk-Power System.[126] In response, NERC and WECC recommended a review of Reliability Standard PRC–024–2 to determine whether to modify it for clarity and to ensure a more accurate representation of Bulk-Power System frequency measurement.[127] Shortly after the Blue Cut Fire Event Report, NERC also issued the Loss of Solar Resources Alert I identifying and recommending corrective action to prevent similar IBR responses in the future.[128]

59. On July 9, 2020, the Commission approved Reliability Standard PRC–024–3, which addressed some of the reliability gaps in Reliability Standard PRC–024–2 that NERC found contributed to the outages during the August 2016 Blue Cut Fire event system disturbance.[129] For example, Reliability Standard PRC–024–3 clarifies that the ''applicable protection does not cause the generating resource to trip or cease injecting current within the 'no trip zone' during a frequency excursion. . . .'' [130] In addition, Reliability Standard PRC–024–3 requires that frequency be calculated over a window of time and clarifies that instantaneous trip settings based on instantaneously-calculated frequency measurement are not permissible.[131] However, Reliability Standard PRC–024–3 does not require registered IBRs (or any generator) to remain connected to the Bulk-Power System and to continue to produce real power and support frequency inside the ''no trip zone.'' This reliability gap led to NERC and Texas RE recommending in the 2021 Odessa Disturbance Report the development of a new ride through standard to replace Reliability Standard PRC–024–3 focusing specifically on generator-ride through performance.[132]

b. Voltage Ride Through

60. The Reliability Standards do not require registered IBRs to continually produce real power and support voltage inside the ''no trip zone'' during a voltage excursion. The Reliability Standards also do not have voltage ride through performance requirements that address the unique protection and control functions of registered IBRs that can cause tripping and momentary cessation, even when the IBR voltage protection settings are compliant with Reliability Standard PRC–024–3. Keeping generation resources connected to the grid during and after a Bulk-Power System disturbance is critical to maintaining reliability. During both Bulk-Power System fault and post-fault periods, the transmission system experiences voltage depressions. Additionally, the transmission system may experience high voltages during post-fault recovery periods. Voltage fluctuations during system disturbances may lead to IBRs tripping and momentary cessation, which can exacerbate Bulk-Power System recovery.

61. Since first identifying that IBRs momentarily cease current injection or trip in response to voltage fluctuations during system disturbances, NERC has continued to find that the majority of installed inverters fail to continuously inject active or reactive current during abnormal voltages (*i.e.,* ride through).[133] Through event reports, NERC and WECC have recommended that momentary cessation should not be used for new IBRs and ''should be eliminated or mitigated to the greatest extent possible for existing [IBRs] connected to the [Bulk-Power System].'' and WECC also noted that for existing IBRs with an equipment limitation that requires momentary cessation, ''active current injection following voltage recovery should be restored very quickly (within 0.5 seconds).'' [134]

62. In addition to event reports, NERC has also recommended in the Loss of Solar Resources Alert II that registered IBR owners and operators as well as unregistered IBR owners and operators take action to address voltage ride through and ensure the timely restoration of current injection following momentary cessation by all inverter-based resources connected to the Bulk-Power System.[135] NERC also recommended that solar PV IBR owners should ''[w]ork with their inverter manufacturer(s) to identify the changes that can be made to eliminate momentary cessation of current injection to the greatest extent possible, consistent with equipment capability.'' [136]

purposes of jurisdictional wholesale sales.'' *Id.* P 12.

[124] *Essential Reliability Servs. & the Evolving Bulk-Power Sys.—Primary Frequency Response,* Order No. 842, 162 FERC ¶ 61,128 at P 1.

[125] Reliability Standard PRC–024–3, Attachment 1, nn.8, 9. There is no explicitly stated expected performance requirements for IBRs while system operating conditions are within the no-trip zone. Therefore, IBRs could continue to act adversely in response to normally cleared faults by continuing to exhibit momentary cessation and power reduction behaviors.

[126] Blue Cut Fire Event Report at v, 15.

[127] *Id.*

[128] Loss of Solar Resources Alert I at 1–2.

[129] *N. Am. Elec. Reliability Corp.,* Docket No. RD20–7–000 (July 9, 2020) (delegated letter order).

[130] Cessation of current injection was not included in Reliability Standard PRC–024–2. *See also* Reliability Standard PRC–024–3, Requirement R1 & Attachment 1, n.9.

[131] Reliability Standard PRC–024–3, Attachment 1, n.9.

[132] Odessa Disturbance Report at 30.

[133] Blue Cut Fire Event Report at 9; Canyon 2 Fire Event Report at 14, 16–17, 20; Angeles Forest and Palmdale Roost Events Report at 13, 15, 19; San Fernando Disturbance Report at iv, 2–9.

[134] Canyon 2 Fire Event Report at 19.

[135] Loss of Solar Resources Alert II at 1.

[136] *Id.* at 2–3.

63. For IBRs for which momentary cessation cannot be eliminated entirely, NERC recommended that generator owners should identify the changes that can be made to inverter settings to minimize the impact of momentary cessation on the Bulk-Power System.[137] NERC also recommended that solar PV IBR owners should ''consult with their inverter manufacturer(s) and their PV panel manufacturer(s) to implement inverter DC reverse current protection settings based on equipment limitations, such that the resource will not trip unnecessarily during high voltage transients on the [Bulk-Power System.]'' [138] Also in the IBR Performance Guideline, NERC recommends reducing the recovery delay on the order of one to three electrical cycles and return to full active power within one second. The only exception to the return to service recommendation is when the transmission planner or generation interconnection studies specify a longer period to return to normal operations. Longer restoration periods would require other essential reliability services from other generators to be deployed to arrest frequency decline and provide voltage support when IBRs trip or do not return to service in a timely manner.[139]

c. Post-Disturbance IBR Ramp Rate Interactions

64. The Reliability Standards do not ensure that all generation resources that momentarily cease operation following a system disturbance return to pre-disturbance output levels without impeded ramp rates. In the Canyon 2 Fire Event Report, NERC and WECC explained that impeded ramp rates need to be ''remediated to ensure [Bulk-Power System] transient and frequency stability.'' [140] Further, NERC and WECC found that IBR ramp rates are artificially bounded, resulting in IBRs returning to pre-disturbance outputs slower than desired—ranging from seconds to several minutes—because plant-level controller ramp rate limits used for balancing generation and load are being applied to IBRs following momentary cessation.[141] For IBRs that cannot eliminate momentary cessation, NERC and WECC recommended that active current injection should not be restricted by a plant-level controller or other limits on ramp rates.[142] NERC and WECC also recommended that IBR owners should remediate post-disturbance ramp rate limitations in close coordination with their balancing authority and inverter manufacturers while ensuring that ramp rates are enabled appropriately to control generation-load balance.[143]

d. Phase Lock Loop Synchronization

65. The Reliability Standards do not require that all generation resources maintain voltage phase angle synchronization with the Bulk-Power System grid voltage during a system disturbance. IBRs will momentarily cease current injection into the grid due to protection and control settings during Bulk-Power System disturbance events if IBRs lose synchronization with grid voltage (*i.e.,* phase lock loop loss of synchronism). The Odessa Report explained that phase lock loop loss of synchronism was the largest contributor to the reduction of solar PV output during the reported Bulk-Power System disturbance event.[144]

66. For IBRs, an inverter phase lock loop ''continually monitors the phase angle difference between the inverter [AC] voltage command and the grid-side [AC] voltage.'' [145] The phase lock loop also ''adjusts the internal phase angle of current injection to remain synchronized with the [AC] grid.'' [146] Synchronous generation resources do this automatically through electromagnetic coupling whereby mechanical energy from the turbine is converted to electrical energy in the magnetic field of the generator, which is synchronized with the system.[147] For certain disturbances, a ''rapid change in inverter terminal phase angle can pose challenges for the [phase lock loop] to track the terminal voltage angle.'' [148] In some instances, a phase lock loop ''loss of synchronism'' may occur.[149] Proper tracking of voltage phase angle is required for a successful and effective synchronization of the inverter with the grid.

67. The Canyon 2 Fire Event Report found that some IBRs experienced a momentary loss of synchronism with the AC grid waveform during the disturbance, which resulted in protective action opening the primary circuit breaker followed by a five-minute restart action.[150] NERC and WECC recommended that IBRs should ''ride through momentary loss of synchronism'' during Bulk-Power System disturbances and that they should continue to inject current into the Bulk-Power System during the disturbance.[151]

IV. Proposed Directives

68. We preliminarily find that the Reliability Standards do not adequately address the impacts of IBRs on the reliable operation of the Bulk-Power System. Informed by the IBR events, reports, alerts, and guidelines discussed above, we preliminarily find that changes to the Reliability Standards are necessary to appropriately address IBRs and their impacts on Bulk-Power System operations.

69. Pursuant to section 215(d)(5) of the FPA and § 39.5(f) of the Commission's regulations, we therefore propose to direct NERC to develop and submit new or modified Reliability Standards that address the impacts of IBRs on the reliable operation of the Bulk-Power System as described in more detail below. Given the current and projected increased proportion of IBRs within the Bulk-Power System generation fleet,[152] we propose to direct NERC to develop new or modified Reliability Standards that address: (1) IBR data sharing; (2) IBR model validation; (3) IBR planning and operational studies; and (4) registered IBR performance requirements.

70. We appreciate that NERC has initiated several standard drafting projects relating to IBRs,[153] but we

[137] *Id.* at 3.

[138] *Id.* at 4.

[139] NERC IBR Performance Guideline at 13, 68.

[140] Canyon 2 Fire Event Report at 9.

[141] *Id.* at 9–11, 19; *see also* Blue Cut Fire Event Report at 15 (observing that during the Blue Cut Fire Event, some inverters that went into momentary cessation mode returned to pre-disturbance levels at a slow ramp rate).

[142] Canyon 2 Fire Event Report at v.

[143] *Id. See also* Loss of Solar Resources Alert II at 3 (recommending that IBR solar PV generators owners ensure that inverter restoration from momentary cessation should not be impeded by plant-level control ramp rates); *see also* Angeles Forest and Palmdale Roost Events Report at 14–15 (reiterating the findings and recommendations from the Loss of Solar Resources Alert II); *see also* San Fernando Disturbance Report at iv (explaining that some IBRs returned to pre-disturbance power output levels quickly (*i.e.,* around one second) while the majority of IBRs had longer ramp rates and required substantially more time to return to pre-disturbance power output levels).

[144] Odessa Report at 8.

[145] IBR Interconnection Requirements Guideline at 9 (footnotes omitted).

[146] *Id.*

[147] Edvard, *Mysterious Synchronous Operation of Generator Solved,* Electrical-Engineering-Portal.com, (Jun. 2013), *https://electrical-engineering-portal.com/mysterious-synchronous-operation-of-generator.*

[148] IBR Interconnection Requirements Guideline at 9.

[149] *Id.* at 10 (this is a protective function that operates when the angle difference between the phase generated by the phase lock loop and the grid phase exceeds a threshold for a predetermined period, typically on the order of a couple of milliseconds).

[150] Canyon 2 Fire Event Report at 15–16, 20.

[151] *Id.*

[152] *See, e.g.,* 2020 LTRA Report at 9.

[153] NERC 2022–2024 Reliability Standards Development Plan.

believe that a comprehensive review and development of new or modified Reliability Standards to address IBRs is necessary to assure that IBRs are properly considered in Bulk-Power System planning and that their operational characteristics—such as momentary cessation—are addressed.[154] Developing new or modified Reliability Standards to comprehensively address the reliability impacts of IBRs will help ensure the reliable operation of the Bulk-Power System as the transition to a future resource mix that includes a high level of IBR penetration continues.

71. Given the variety of concerns related to IBRs, there may be efficiencies in developing a new IBR-specific Reliability Standard or Standards that address IBR issues in a comprehensive manner. Further, considering the directives in the related IBR registration order issued concurrently with this NOPR,[155] a new Reliability Standard or Standards may also be more easily developed for the newly registered IBR-only generator owners and operators of currently unregistered IBRs that fall outside the current bulk electric system definition but that, in the aggregate, materially impact the reliable operation of the Bulk-Power System.[156] We do not propose to direct any specific method for addressing the reliability concerns discussed herein; rather, NERC has the discretion, subject to Commission review and approval, to address the reliability concerns by developing one or more new Reliability Standards or modifying currently effective Reliability Standards.

72. We propose to direct NERC to submit a compliance filing within 90 days of the effective date of the final rule in this proceeding. That compliance filing shall include a detailed, comprehensive standards development and implementation plan explaining how NERC will prioritize the development and implementation of new or modified Reliability Standards. In its compliance filing, NERC should explain how it is prioritizing its IBR Reliability Standard projects to meet the directives in the final rule, taking into account the risk posed to the reliability of the Bulk-Power System, standard development projects already underway, resource constraints, and other factors as necessary.

73. We propose to direct NERC to use a staggered approach that would result in NERC submitting new or modified Reliability Standards in three stages: (1) new or modified Reliability Standards including directives related to registered IBR failures to ride through frequency and voltage variations during normally cleared Bulk-Power System faults shall be filed with the Commission within 12 months of Commission approval of the plan; (2) new or modified Reliability Standards addressing the interconnected directives related to registered IBR, unregistered IBR, and IBR–DER data sharing, registered IBR disturbance monitoring data sharing, registered IBR, unregistered IBR, and IBR–DER data and model validation, and registered IBR, unregistered IBR, and IBR–DER planning and operational studies shall be filed with the Commission within 24 months of Commission approval of the plan; and (3) new or modified Reliability Standards including the remaining directives for post-disturbance ramp rates and phase-locked loop synchronization shall be filed with the Commission within 36 months of Commission approval of the plan. We believe this staggered approach to standard development may be necessary based on the scope of work anticipated and that specific target dates will provide a valuable tool and incentive to NERC to timely address the directives in the final rule.

74. NERC should also reflect in its compliance filing that the proposed directives for individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate, related to data sharing, validation, and use in studies are interdependent. For example, data models and validation build and rely upon the data sharing directives. Similarly, the planning and operational study directives require the use of validated models and data sharing. We believe that this proposal strikes a reasonable balance between the need to timely implement identified improvements to the Reliability Standards that will further Bulk-Power System reliability and the need for NERC to develop modifications with industry input using its open, stakeholder process.

75. We seek comments from NERC and other interested entities on this staggered approach, including the 90-day timeframe to submit a compliance filing with a development and implementation plan, and on all other proposals in this NOPR.

A. IBR and IBR–DER Data Sharing

76. We preliminarily find that the current Reliability Standards are inadequate to ensure that sufficient data of registered IBRs and unregistered IBRs, and IBR–DER data in the aggregate is provided to the registered entities responsible for planning, operating, and analyzing disturbances on the Bulk-Power System. The currently effective Reliability Standards, such as TOP–003–4 (Operational Reliability Data) and IRO–010–3 (Reliability Coordinator Data Specification and Collection), require the data recipient (*e.g.,* transmission operator, reliability coordinator) to specify a list of data to be provided, and obligates other identified registered entities (*e.g.,* generator owner, generator operator, transmission owner, distribution provider) to provide the specified data. Although Reliability Standards TOP–003–4 and IRO–010–3, along with other data-related Reliability Standards (including MOD–032–1 and PRC–002–2) are effective and enforceable, we preliminarily find that these Reliability Standards do not require generator owners, generators operators, transmission owners, and distribution providers to provide data that represents the behavior of both individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate, at a sufficient level of fidelity for planners and operators to accurately plan, operate, and analyze disturbances on the Bulk-Power System.

77. To address this gap in the Reliability Standards, we propose to direct NERC to develop new or modified Reliability Standards that identify: (1) the registered entities that must provide certain data of registered IBRs and unregistered IBRs, as well as IBR–DER data in the aggregate; (2) the recipients of that registered IBR, unregistered IBR, and IBR–DER data; (3) the minimum categories or types of registered IBR, unregistered IBR, and IBR–DER related data that must be provided; and (4) the timing and periodicity for the provision of registered IBR, unregistered IBR, and IBR–DER data needed for modeling, operations, and disturbance analysis to the appropriate registered entities and the review of that data by those entities.

78. Further, we propose to direct NERC to ensure that the new or modified Reliability Standards require registered generator owners and generator operators of registered IBRs to provide registered IBR-specific

[154] *See* 2021 Solar PV Disturbances Report, vi, 30 (stating that the report ''strongly reiterates the recommendations in the Odessa Disturbance Report regarding the need to modernize and update the . . . Reliability Standards.'').

[155] *See Registration of Inverter-based Resources,* 181 FERC ¶ 61,124 at P 32 (directing that NERC identify and register unregistered IBRs that, in the aggregate, have a material impact on the reliable operation of the Bulk-Power System, but that are not currently required to be registered with NERC under the [bulk electric system] definition.'').

[156] *Id.* P 33 (''NERC may determine that the full set of Reliability Standard Requirements otherwise applicable to generator owners and operators need not apply to currently unregistered IBR generator owners and operators when they are registered.'' (citation omitted)).

modeling data and parameters (*e.g.,* steady-state, dynamic and short circuit modeling information, and control settings for momentary cessation and ramp rates) that are complete and accurate to their planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities that are responsible for planning and operating the Bulk-Power System. This approach would provide the registered entities responsible for planning and operating the Bulk-Power System with accurate data on registered IBRs. We propose to direct NERC to include technical criteria for having disturbance monitoring equipment at buses and elements of registered IBRs to ensure disturbance monitoring data is available to the planners and operators for analyzing disturbances on the Bulk-Power System and to validate registered IBR models.

79. We also preliminarily find that planning coordinators and other entities also need modeling data and parameters from both unregistered IBRs as well as IBR–DERs in the aggregate to assure greater accuracy in modeling. We propose to direct that the new or modified Reliability Standards addressing IBR data sharing require transmission owners to provide modeling data and parameters (*e.g.,* steady-state, dynamic and short circuit modeling information, and control settings for momentary cessation and ramp rates) for unregistered IBRs in their transmission owner areas where the unregistered IBRs that individually or in the aggregate materially affect the reliable operation of the Bulk-Power System. Similarly, where entities that own or operate IBR–DERs that, in the aggregate, materially affect the reliability of the Bulk-Power System and are not subject to compliance with Reliability Standards, we propose to direct that the new or modified Reliability Standards addressing IBR data sharing require that the distribution provider provide modeling data and parameters for IBR–DERs in the aggregate connected in its distribution provider area.[157]

80. This approach would be similar to other Reliability Standards that require transmission owners and distribution providers to provide certain planning and operational data received from unregistered entities.[158] Moreover, given the small size and location of many of the IBR–DERs on the distribution system, we recognize that it may not be practical for distribution providers to provide modeling data and parameters to model individual IBR–DERs directly. Instead, the new or modified Reliability Standards should permit distribution providers to provide IBR–DER modeling data and parameters in the aggregate or equivalent for IBR–DERs interconnected to their distribution systems (*e.g.,* IBR–DERs in the aggregate and modeled by resource type such as wind or solar PV, or IBR–DERs in the aggregate and modeled by interconnection requirements performance to represent different steady-state and dynamic behavior).[159]

81. We believe that these proposed directives will ensure that entities such as planning coordinators and reliability coordinators receive accurate and complete data about IBRs, both registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate to properly plan, operate, and analyze performance on the Bulk-Power System to ensure reliable operations.

B. IBR and IBR–DER Data and Model Validation

82. We preliminarily find that the existing Reliability Standards are inadequate to ensure that planners and operators: (1) have the steady state, dynamic, and short circuit models of the elements that make up generation, transmission, and distribution facilities that accurately reflect the generator behavior in steady state and dynamic conditions; (2) have dynamic models (*i.e.,* models of equipment that reflect the equipment's behavior during various grid conditions and disturbances) that accurately represent the dynamic performance of all generation resources, including momentary cessation when applicable; (3) validate and update resource models by comparing the provided data and resulting models against actual operational behavior to achieve and maintain necessary accuracy of their resource models; and (4) have interconnection-wide planning and operational models that represent all generation resources, including: registered IBRs, unregistered IBRs, and IBR–DERs; synchronous generation; and load resource models. System planners and operators need accurate planning, operational, and interconnection-wide models to ensure reliable operation of the system.

83. We therefore propose to direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that would ensure that all necessary models are validated. Specifically, NERC should ensure that the Reliability Standards require: (1) generator owners to provide validated registered IBR models to the planning coordinators for interconnection-wide planning and operational models; (2) require transmission owners to provide validated unregistered IBR models to the planning coordinators for interconnection-wide planning and operational models; and (3) require distribution providers to provide validated models of IBR–DERs in the aggregate (*e.g.,* IBR–DERs in the aggregate and modeled by resource type such as wind or solar PV, or IBR–DERs in the aggregate and modeled by interconnection requirements performance to represent different steady-state and dynamic behavior) to the planning coordinators for interconnection-wide planning and operational models. Further, NERC should ensure that the new or modified Reliability Standards require models of individual registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate to represent the dynamic behavior of these IBRs at a sufficient level of fidelity for planners and operators to perform valid facility interconnection, planning, and operational studies on a basis comparable to synchronous generation resources.

84. The Reliability Standards do not require a generator owner to provide verified models and data for IBR-specific controls (*e.g.,* power plant central controller functions and protection system settings) and do not require verified dynamic models from the transmission owner for unregistered IBRs or require verified IBR–DERs dynamic models in the aggregate from distribution providers. We therefore

[157] NERC, *Reliability Guideline: Parameterization of the DER A Model,* 8–16 (Sept. 2019), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_A_Parameterization.pdf.*

[158] This approach is consistent with certain currently effective Reliability Standards. *See, e.g.,* Reliability Standard IRO–010–2 (Reliability Coordinator Data Specification and Collection) Requirement R1 (providing that ''[t]he Reliability Coordinator shall maintain a documented specification for the data . . . *including non-[bulk electric system] data*''(emphasis added)), Requirement R2 (providing that ''[t]he Reliability Coordinator shall distribute its data specification to entities''), Requirement R3 (providing that ''[e]ach . . . Transmission Owner, and Distribution Provider receiving a data specification in Requirement R2 shall satisfy the obligations of the documented specifications''); Reliability Standard PRC–006–3 (Automatic Underfrequency Load Shedding) Requirement R8 (requiring that a UFLS entity, *i.e.,* relevant transmission owner and distribution provider, ''provide data to its Planning Coordinator(s)'').

[159] NERC DER Report at 7 (explaining ''a certain degree of simplification may be needed either by model aggregation (*i.e.,* clustering of models with similar performance), by derivation of equivalent models (*i.e.,* reduced-order representation), or by a combination of the two.''). *See also* NERC, *Reliability Guideline: Parameterization of the DER A Model,* (Sept. 2019), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_A_Parameterization.pdf.*

propose to direct that the proposed new or modified Reliability Standards account for the technological differences between Bulk-Power System IBRs and synchronous generation resources. We also propose to direct NERC to require generator owners of registered IBRs and transmission owners that have unregistered IBRs on their system to ensure that the dynamic models provided to the planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities accurately represent the dynamic performance of registered IBR and unregistered IBR facilities, including momentary cessation and/or tripping, including all ride through behavior. Further, we propose to direct NERC to require distribution providers that have IBR–DERs on their system to ensure that the aggregated dynamic models provided to the planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities accurately represent the dynamic performance of IBR–DER facilities in the aggregate, including momentary cessation and/or tripping, including all ride -through behavior (*e.g.,* IBR–DERs in aggregate modeled by interconnection requirements performance to represent different steady-state and dynamic behavior).

85. We also preliminarily find that there is a coordination gap among registered entities that build and verify interconnection-wide cases. Reliability Standards MOD–032–1 and MOD–033–2 functional entities and designees are not required to work collaboratively to create interconnection-wide cases that accurately reflect real-world interconnection-wide IBR performance and behavior. Therefore, we propose to direct NERC to ensure that the new or modified Reliability Standards require planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities to validate, coordinate, and keep up-to-date in a timely manner [160] the verified data and models of registered IBRs, unregistered IBRs, and IBR–DERs in the aggregate by comparing their data and resulting models against actual operational behavior to achieve and maintain necessary modeling accuracy of individual and aggregate registered IBR and unregistered IBR performance and behaviors, as well as performance and behaviors of IBR–DERs in the aggregate.

[160] Panhandle Report at 19 (recommending that the performance validation feedback loop is addressed in a timely manner).

86. Finally, without approved generator models that accurately reflect the generator behavior in steady state and dynamic conditions, we preliminarily find that planners and operators are unable to adequately predict IBR behavior and their subsequent impact on the Bulk-Power System.[161] The Reliability Standards do not require the use of NERC's approved component models, instead models are referred to generally in Reliability Standard MOD–032–1, Attachment 1.[162] We therefore propose to require that the new or modified Reliability Standards require the use of approved industry IBR models that accurately reflect the behavior of IBRs during both steady state and dynamic conditions. One way to do this would be to reference NERC's approved model list in the Reliability Standards and require that only those models be used when developing planning, operational, and interconnection-wide models. The proposed directives are consistent with the recommendations in NERC reports.[163]

C. IBR and IBR–DER Planning and Operational Studies

87. We preliminarily find that the existing Reliability Standards are inadequate to ensure planning and operational studies: (1) assess performance and behavior of both individual and aggregate registered IBRs and unregistered IBRs as well as IBR–DERs in the aggregate; (2) have and use validated modeling and operational data for individual registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate; and (3) account for the impacts of both individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate, within and across planning and operational boundaries for normal operations and contingency event conditions. Planning and operational studies must use validated IBR modeling and operational data to ensure studies account for the actual behavior of both individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate.

[161] NERC Standardized Powerflow Parameters and Dynamics Models (explaining that there is a growing need for accurate interconnection-wide powerflow and dynamics simulations that analyze phenomena such as: frequency response, inter-area oscillations, and interactions between the growing numbers of wide-area control and protections systems).

[162] Reliability Standard MOD–032–1, Attachment 1 (explaining that if a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables).

[163] *See, e.g.,* Modeling and Studies Report at 37 (recommending revising Reliability Standards to ensure that large disturbance behavior of IBRs is verified); WI Base Case IBR Review at v (recommending that IBR owners ensure that all data fields are reported correctly and that transmission planners and planning coordinators ''should verify that the data fields are submitted correctly'').

1. Planning Studies

88. We preliminarily find that the Reliability Standards do not ensure accurate planning studies of Bulk-Power System performance over a broad spectrum of system conditions and following a wide range of probable contingencies that includes all resources. Inaccurate planning assessments may lead to false expectations that system performance requirements are met and may inadvertently mask potential reliability risks in planning and operations. We therefore propose to direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that would require planning coordinators and transmission planners to include in their planning assessments the study and evaluation of performance and behavior of individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate, under normal and contingency system conditions in their planning area. We further propose that the planning assessments include the study and evaluation of the ride through performance (*e.g.,* tripping and momentary cessation conditions) of such IBRs in their planning area for stability studies on a comparable basis to synchronous generation resources. The proposed Reliability Standard(s) would also require planning coordinators and transmission planners to consider the individual and aggregate behavior of registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate, using planning models of their area, and, using interconnection-wide area planning models, IBR behavior in adjacent and other planning areas that adversely impacts a planning coordinator's or transmission planner's area during a disturbance event. We believe that this is needed because registered IBRs, unregistered IBRs, and IBR–DERs tend to act in the aggregate over a wide area during such an event.[164]

[164] 2021 Solar PV Disturbances Report at v (stating that ''The ongoing widespread reduction of solar PV resources continues to be a notable reliability risk to the [Bulk-Power System], particularly when combined with the additional loss of other generating resources on the [Bulk-Power System] and in aggregate on the distribution system.''); *see also* Odessa Disturbance Report at v (stating that ''[w]hile the ERO has analyzed

2. Operational Studies

89. We preliminarily find that the Reliability Standards do not require that the various operational studies (including operational planning analyses, real-time monitoring, real-time assessments and other analysis functions) include all resources to adequately assess the performance of the Bulk-Power System for normal and contingency conditions. We therefore propose to direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that would require reliability coordinators and transmission operators to include the performance and behavior of both individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate (*e.g.,* IBRs tripping or entering momentary cessation individually or in the aggregate) in their operational planning analysis,[165] real-time monitoring, and real-time assessments [166] including non-bulk electric system data and external power system network data identified in their data specifications.[167] We further propose to direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that would require balancing authorities to include the performance and behavior of both individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate (*e.g.,* resources tripping or entering momentary cessation individually or in the aggregate) in their operational analysis functions and real-time monitoring.[168] This proposal is consistent with the recommendations in the NERC DER Report, IBR Performance Guideline, IBR–DER Data Collection Guideline, and Loss of Solar Resources Alert II. These reports indicate that a significant amount of IBRs that have been involved in system disturbances were not adequately modeled in interconnection-wide cases and tools used to study the performance and behavior of both individual and aggregate registered IBRs and unregistered IBRs, as well as IBR–DERs in the aggregate.[169] Thus, neighboring operators may be unaware that faults in one operator's area can trigger controls actions and trip IBRs in another operator's area.

D. IBR Performance Requirements

90. We preliminarily find that the Reliability Standards should require registered IBRs to ride through system disturbances to support essential reliability services. Without the availability of essential reliability services, the system would experience instability, voltage collapse, or uncontrolled separation.[170] Therefore, we propose to direct NERC to develop new or modified Reliability Standards that would require generator owners and generator operators to ensure that their registered IBR facilities ride through system frequency and voltage disturbances where technologically feasible. Ride through performance during system disturbances is necessary for registered IBRs to support essential reliability services.[171] We propose to direct NERC to ensure that the proposed new or modified Reliability Standards clearly address and document the technical differences and technical capabilities between registered IBRs and synchronous generation resources in order for registered IBRs to provide support for these essential reliability services.[172]

91. We also propose to direct NERC to develop new or modified Reliability Standards to address other registered IBR performance and operational characteristics that can affect the reliable operation of the Bulk-Power System, namely, ramp rate interactions and phase-locked loop synchronization.

92. We believe the proposed directives would improve the reliable operation of the Bulk-Power System by helping to avoid instability, voltage collapse, uncontrolled separation, or islanding.

1. Frequency Ride Through

93. We preliminarily find that the currently effective Reliability Standards do not require registered IBR reliable frequency ride through performance during system disturbances. The frequency of an interconnection depends on the instantaneous balance between load and generation resources to which all resources must contribute during both normal and contingency conditions. However, the Reliability Standard PRC–024–3 requirement for specific relay protection frequency settings does not ensure adequate registered IBR performance because IBRs could have protection and control functions that can cause the resource to trip or momentarily cease operation even when the IBR frequency protection settings are compliant with the standard. We therefore propose to direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that would require registered IBR generator owners and registered IBR generator operators to use appropriate settings (*i.e.,* inverter, plant controller, and protection) that will assure frequency ride through during system disturbances and that would permit registered IBR tripping only to protect the registered IBR equipment. Under this proposal, any new or modified Reliability Standards should require registered IBRs to continue to produce power and perform frequency support during system disturbances. We believe this proposal is consistent with

multiple similar events in California, this is the first disturbance involving a widespread reduction of solar photovoltaic (PV) resource power output observed in the Texas Interconnection.''); Blue Cut Fire Event Report at 2 (explaining that the system disturbance event was ''impactful because of the widespread loss . . . of PV generation.'').

[165] NERC defines operational planning analysis as ''An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services).'' NERC Glossary.

[166] NERC defines real-time assessment as an ''evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services).'' *Id.*

[167] *See, e.g.,* Reliability Standard IRO–010–2, Requirement R1, part 1.1 and Reliability Standard TOP–003–3 (Operational Reliability Data), Requirement R1, part 1.1.

[168] *See, e.g.,* Reliability Standard TOP–003–3, Requirement R2, part 2.1.

[169] Modeling and Studies Report iv–v.

[170] Essential Reliability Services Concept Paper at iii.

[171] NERC defines essential reliability services to include ''necessary operating characteristics'' provided by ''[c]onventional generation with large rotating mass,'' which are ''needed to reliably operate the North American electric grid.'' NERC explains that essential reliability services ''are an integral part of reliable operations to assure the protection of equipment, and are the elemental 'reliability building blocks' provided by generation.'' *Id.*

[172] There are similar reliability impacts posed by tripping or momentary cessation of unregistered IBRs and IBR–DERs during Bulk-Power System disturbances; however, we are not proposing to direct NERC to develop new or modified Reliability Standards that would address unregistered IBR or IBR–DER performance requirements. We expect that any currently unregistered IBRs that become registered IBRs in the future following an approved NERC workplan in Docket No. RD22–4–000 would be required to comply with any applicable new or modified IBR performance Reliability Standards proposed in this NOPR once those Reliability Standards become enforceable.

recommendations from multiple event reports, including the Blue Cut Fire Event Report,[173] the Odessa Disturbance Report,[174] and most recently the 2021 Solar PV Disturbances Report.[175]

2. Voltage Ride Through

94. We preliminarily find that the currently effective Reliability Standards do not adequately address registered IBR protection and controls settings to allow for voltage ride through during system disturbances (as discussed above in Section III.B.4.b. Voltage Ride Through). We propose to direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that would require registered IBR generator owners and registered IBR generator operators to use appropriate and coordinated registered IBR protection and controls settings that will allow for voltage ride through during system disturbances and would permit registered IBR tripping only when necessary to protect the registered IBR equipment. Under this proposal, any new or modified Reliability Standard should require generator owners of registered IBR facilities to ensure that they prohibit momentary cessation in the no-trip zone during disturbances.[176]

95. We are aware that certain registered IBRs currently in operation may not be able to meet the requirements proposed above. Therefore, we propose to direct NERC to require transmission planners and operators to implement mitigation activities that may be needed to address any reliability impact to the Bulk-Power System posed by these existing facilities. We believe that planners and operators should be able to accommodate this limited number of affected existing registered IBRs, and we expect that the technology of newer IBRs will not require such accommodation.

3. Post-Disturbance IBR Ramp Rate Interactions

96. We preliminarily find that the current Reliability Standards do not sufficiently address registered IBR post-disturbance ramp rates following momentary cessation such that Bulk-Power System transient and frequency stability is supported during the system disturbances.[177] We propose to direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that would require registered IBR post-disturbance ramp rate not to be restricted or to artificially interfere with the resource returning to pre-disturbance output level in a quick and stable manner after a Bulk-Power System fault event. Further, we propose generator owners communicate to the relevant planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels (*i.e.,* generation-load balance). The proposed Reliability Standards should account for the technical differences between registered IBRs and synchronous generation resources, such as registered IBRs' faster control capability to ramp power output down or up when capacity is available. We believe this proposal is consistent with the recommendations in various NERC reports discussed above.[178]

4. Phase Lock Loop Synchronization

97. We preliminarily find that the current Reliability Standards do not require that all generation resources maintain voltage phase angle synchronization with the Bulk-Power System grid voltage during a system disturbance (as discussed in above Section III.B.4.d. Phase Lock Loop Synchronization). In other words, the current Reliability Standards do not adequately address registered IBR's momentary loss of synchronism caused by phase jumps during Bulk-Power System disturbance events. This results in protective action to open the inverter primary circuit breaker (*i.e.,* phase lock loop loss of synchronism). We propose to direct NERC to submit to the Commission for approval one or more new or modified Reliability Standards that would require registered IBRs to ride through any conditions not addressed by the proposed Reliability Standards that address frequency or voltage ride through phase lock loop loss of synchronism. We note that NERC reported that phase lock loop loss of synchronism was a large contributor to the reduction of solar PV output during IBR related Bulk-Power System disturbance events that resulted in the unexpected loss of resources placing additional reliability risk on the Bulk-Power System.[179] We believe this proposal is consistent with the IBR Interconnection Requirements Guideline and Canyon 2 Fire Event Report recommendations. The proposed Reliability Standards should require registered IBRs to ride through momentary loss of synchronism during Bulk-Power System disturbances and require registered IBRs to continue to inject current into the Bulk-Power System at pre-disturbance levels during a disturbance.

V. Information Collection Statement

98. This NOPR proposes to direct the ERO to develop and submit to the Commission for approval one or more new or modified Reliability Standards and submit a compliance filing that includes a standards development plan for the new or modified reliability standards that address IBRs. The Paperwork Reduction Act (PRA) requires each federal agency to seek and obtain OMB approval before undertaking a collection of information directed to ten or more persons or contained in a rule of general applicability. Reliability Standards Development as described in FERC–725 covers standards development initiated by NERC, the Regional Entities, and industry, as well as standards the Commission may direct NERC to develop or modify.

99. The proposal to direct NERC to develop new, or to modify existing, Reliability Standards (and the corresponding burden) are covered by, and already included in, the existing OMB-approved information collection FERC–725 (Certification of Electric Reliability Organization; Procedures for Electric Reliability Standards; OMB Control No. 1902–0225), under Reliability Standards Development.[180] The reporting requirements in FERC–725 include the ERO's overall responsibility for developing Reliability Standards.

- *Necessity of the Information:* The proposed directive to the ERO to develop and submit to the Commission for approval one or more new or modified Reliability Standards, if adopted, would implement the Congressional mandate of the Energy Policy Act of 2005 to develop mandatory and enforceable Reliability Standards to better ensure the reliability of the nation's Bulk-Power System.

[173] Blue Cut Fire Report at 11–13.

[174] Odessa Disturbance Report at vii, 12–13.

[175] 2021 Solar PV Disturbances Report at vii, 15, 31.

[176] We note that Reliability Standard PRC–024–3, Attachments 1 and 2 clarify that the area outside the No Trip Zone is not a Must Trip Zone.

[177] *See* Canyon 2 Fire Event Report at 9.

[178] *See, e.g., id.* (explaining that impeded ramp rates need to be ''remediated to ensure [Bulk-Power System] transient and frequency stability''); Blue Cut Fire Event Report at 15 (observing that during the Blue Cut Fire Event, some inverters that went into momentary cessation mode returned to pre-disturbance levels at a slow ramp rate).

[179] *See* Section III.B.4.d.

[180] Reliability Standards Development as described in FERC–725 covers standards development initiated by NERC, the Regional Entities, and industry, as well as standards the Commission may direct NERC to develop or modify.

Specifically, the proposal would ensure that the ERO develops and submits for approval new or modified Reliability Standards that would require certain facilities to operate in support of the reliable operation of the Bulk-Power System.

• *Internal review:* The Commission has reviewed the proposed directive that the ERO revise its current Reliability Standards and determined that the proposal is necessary to meet the statutory provisions of the FPA requiring the Commission to ensure the reliability of the Bulk-Power System.

100. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, email: *DataClearance@ferc.gov,* Phone: (202) 502–8663, fax: (202) 273–0873]. Comments on the requirements of this rule may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by email to OMB at *oira_submission@omb.eop.gov.* Please reference OMB Control No. 1902–0225, FERC–725 and the docket number of this proposed rulemaking in your submission.

VI. Environmental Assessment

101. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[181] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[182] The actions proposed here fall within this categorical exclusion in the Commission's regulations.

VII. Regulatory Flexibility Act Certification

102. The Regulatory Flexibility Act of 1980 (RFA)[183] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. By only proposing to direct NERC, the Commission-certified ERO, to develop modifications to Reliability Standards, this NOPR will not have a significant or substantial impact on entities other than NERC. The ERO develops and files with the Commission for approval Reliability Standards affecting the Bulk-Power System, which represents: (a) a total electricity demand of 830 GW (830,000 MW) and (b) more than $1 trillion worth of assets. Therefore, the Commission certifies that this NOPR will not have a significant economic impact on a substantial number of small entities.

103. Any Reliability Standards proposed by NERC in compliance with this rulemaking will be considered by the Commission in future proceedings. As part of any future proceedings, the Commission will make determinations pertaining to the Regulatory Flexibility Act based on the content of the Reliability Standards proposed by NERC.

VIII. Comment Procedures

104. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due February 6, 2023 and Reply Comments are due March 6, 2023. Comments must refer to Docket No. RM22–12–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

105. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's website at *http://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

106. Commenters that are not able to file comments electronically must submit an original of their comments either by mail through the United States Postal Service to: the Secretary of the Commission, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426,[184] or by any other method of delivery, including hand delivery, to the Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, Maryland 20852.[185]

107. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

IX. Document Availability

108. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*http://www.ferc.gov*). At this time, the Commission has suspended access to the Commission's Public Reference Room due to the President's March 13, 2020 proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19).

109. From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

110. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202)502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

By direction of the Commission. Commissioner Danly is concurring with a separate statement attached.

Issued: November 17, 2022.

Debbie-Anne A. Reese,

Deputy Secretary.

Note: The following appendix will not appear in the **Federal Register**

Appendix A

NERC IBR Resources Cited in the NOPR

NERC Guidelines

NERC Guidelines referenced in this NOPR are available here: *https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx.*

NERC, *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance* (Sept. 2018), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Inverter-Based_Resource_Performance_Guideline.pdf* (IBR Performance Guideline).

[181] *Reguls. Implementing the Nat'l Env't Pol'y Act of 1969,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[182] 18 CFR 380.4(a)(2)(ii).

[183] 5 U.S.C. 601–612.

[184] 18 CFR 385.2001(a)(1)(i).

[185] 18 CFR 385.2001(a)(1)(ii).

NERC, *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources* (Sept. 2019), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf* (IBR Interconnection Requirements Guideline).

NERC, *Reliability Guideline: Parameterization of the DER A Model,* (Sept. 2019), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_A_Parameterization.pdf.*

NERC, *Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies,* (Sept. 2020), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_Data_Collection_for_Modeling.pdf* (IBR–DER Data Collection Guideline).

NERC, Reliability Guideline: Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants (Mar. 2021), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_BESS_Hybrid_Performance_Modeling_Studies_.pdf* (BESS Performance Modeling Guideline).

NERC White Papers

IRPTF white papers referenced in this NOPR are available here: *https://nerc.com/comm/PC/Pages/Inverter-Based-Resource-Performance-Task-Force.aspx.*

NERC, *A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability* (Oct. 2014), *https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf* (Essential Reliability Services Concept Paper).

NERC, *Resource Loss Protection Criteria Assessment Whitepaper* (Feb. 2018), *https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/IRPTF_RLPC_Assessment.pdf* (Resource Loss Protection Whitepaper).

NERC, *Fast Frequency Response Concepts and Bulk Power System Reliability Needs* (Mar. 2020), *https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf* (Fast Frequency Response White Paper).

NERC, *IRPTF Review of NERC Reliability Standards White Paper* (Mar. 2020), *https://www.nerc.com/pa/Stand/Project202104ModificationstoPRC0022DL/Review_of_NERC_Reliability_Standards_White_Paper_062021.pdf* (Reliability Standards Review White Paper).

NERC, *San Fernando Disturbance Follow-Up White Paper* (June 2021), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/IRPWG_San_Fernando_Disturbance_Follow-Up_Paper%20(003).pdf* (San Fernando Disturbance White Paper).

NERC, *Utilizing the Excess Capability of BPS-Connected Inverter-Based Resources for Frequency Support* (Sept. 2021), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_IBR_Hybrid_Plant_Frequency_Response.pdf* (Frequency Support White Paper).

NERC, *Odessa Disturbance Follow-up White Paper* (Oct. 2021), *https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Odessa_Disturbance_Follow-Up.pdf* (Odessa Disturbance White Paper).

NERC Reports

NERC, *2013 Long-Term Reliability Assessment* (Dec. 2013), *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf* (2013 LTRA Report).

NERC, *Distributed Energy Resources: Connection Modeling and Reliability Considerations* (Feb. 2017), *https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf* (NERC DER Report).

NERC, *2020 Long Term Reliability Assessment Report* (Dec. 2020), *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf* (2020 LTRA Report).

NERC, *2021 Long Term Reliability Assessment Report* (Dec. 2021), *https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf* (2021 LTRA Report).

NERC Technical Reports

NERC technical reports referenced in this NOPR are available here: *https://nerc.com/comm/PC/Pages/Inverter-Based-Resource-Performance-Task-Force.aspx.*

NERC, *Technical Report, BPS-Connected Inverter-Based Resource Modeling and Studies* (May 2020), *https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/IRPTF_IBR_Modeling_and_Studies_Report.pdf* (Modeling and Studies Report).

NERC and WECC, *WECC Base Case Review: Inverter-Based Resources* (Aug. 2020), *https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/NERC-WECC_2020_IBR_Modeling_Report.pdf* (Western Interconnection (WI) Base Case IBR Review).

NERC Major Event Reports

NERC event reports referenced in this NOPR are available here: *https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx.*

NERC, *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report* (June 2017), *https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf* (Blue Cut Fire Event Report) (covering the Blue Cut Fire event (August 16, 2016)).

NERC and WECC, *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report* (Feb. 2018), *https://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%202%20Fire%20Disturbance%20Report/900%20MW%20Solar%20Photovoltaic%20Resource%20Interruption%20Disturbance%20Report.pdf* (Canyon 2 Fire Event Report) (covering the Canyon 2 Fire event (October 9, 2017)).

NERC and WECC, *April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report* (Jan. 2019), *https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf* (Angeles Forest and Palmdale Roost Events Report) (covering the Angeles Forest (April 20, 2018) and Palmdale Roost (May 11, 2018) events)/

NERC and WECC, *San Fernando Disturbance,* (Nov. 2020), *https://www.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf* (San Fernando Disturbance Report) (covering the San Fernando event (July 7, 2020)).

NERC and Texas RE, *Odessa Disturbance* (Sept. 2021) *https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf* (Odessa Disturbance Report) (covering events in Odessa, Texas on May 9, 2021 and June 26, 2021).

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United States of America

Federal Energy Regulatory Commission

Reliability Standards to Address Inverter-Based Resources

Docket No. RM22–12–000

(Issued November 17, 2022)

DANLY, Commissioner, *concurring:*

1. I concur in today's order.[1] I remain gravely concerned about the North American Electric Reliability Corporation's (NERC) inability to act swiftly and nimbly in response to emerging risks that threaten the reliability of the Bulk-Power System (BPS). This is due in no small part to the statutory framework of Federal Power Act (FPA) section 215.[2] According to NERC's Inverter-Based Resource (IBR) Strategy document,[3] ''[t]he [Electric Reliability Organization (ERO)] Enterprise has analyzed numerous widespread IBR loss events and identified many systemic performance issues with the inverter-based fleet *over the past six years.*'' [4] NERC explains that ''[t]he disturbance reports, alerts, guidelines, and other deliverables developed by the ERO thus far have highlighted that abnormal IBR performance issues pose a significant risk to BPS reliability.'' [5] Our actions today in this and another proceeding [6] propose firm deadlines by which NERC must act to register and hold IBR entities accountable for failure to comply with mandatory and enforceable Reliability Standards.

2. Better late than never, I suppose. Nevertheless, it could be at least four years before certain of the IBR entities are registered and another five years before the full suite of contemplated requirements are mandatory and enforceable. So, it will be about ten or eleven years *after* the significant reliability risk was definitively identified that we will have required registration and Reliability Standards in place. The reliability consequences that attend the rapid deployment of an unprecedented number of IBRs are, at this point, unarguable. As NERC's President and CEO explained last week: ''the pace of the transformation of the electric system needs to be managed and that transition needs to occur in an orderly way.'' [7] Mandatory reliability standards must be implemented as quickly as possible to ensure the reliable operation of the BPS. We at FERC are responsible for the reliability of the BPS under FPA section 215. I fear we may be taking too long to address reliability challenges that urgently need our attention.

For these reasons, I respectfully concur.

James P. Danly,
Commissioner.

[1] *Reliability Standards to Address Inverter-Based Resources,* 181 FERC ¶ 61,125 (2022).

[2] 16 U.S.C. 824o.

[3] NERC, *Inverter-Based Resource Strategy: Ensuring Reliability of the Bulk Power System with Increased Levels of BPS-Connected IBRs* (Issued Sep. 14, 2022), *https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf.*

[4] *Id.* at 3.

[5] *Id.* at 5.

[6] *Registration of Inverter-based Resources,* 181 FERC ¶ 61,124 (2022).

[7] Statement of James B. Robb, Annual Commissioner-led Reliability Technical Conference (Nov. 10, 2022), *https://www.ferc.gov/news-events/events/annual-commissioner-led-reliability-technical-conference-11102022.*

[FR Doc. 2022–25599 Filed 12–5–22; 8:45 am]

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DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 105

[Docket No. USCG–2022–0052]

RIN 1625–AC80

Transportation Worker Identification Credential (TWIC)—Reader Requirements; Second Delay of Effective Date

AGENCY: Coast Guard, DHS.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Coast Guard proposes to further delay the effective date for certain facilities affected by the final rule entitled ''Transportation Worker Identification Credential (TWIC)—Reader Requirements,'' published in the **Federal Register** on August 23, 2016. The current effective date for the final rule is May 8, 2023. The Coast Guard proposes delaying the effective date for: facilities that handle certain dangerous cargoes in bulk, but do not transfer those cargoes to or from a vessel; facilities that handle certain dangerous cargoes in bulk, and do transfer those cargoes to or from a vessel; and facilities that receive vessels carrying certain dangerous cargoes in bulk, but do not, during that vessel-to-facility interface, transfer those bulk cargoes to or from those vessels. Specifically, we propose to delay the effective date for these facilities for 3 years from the original delay expiration date of May 8, 2023 to May 8, 2026, but invite comments as well on possibly extending the delay through as late as May 8, 2029. This delay will give the Coast Guard time to further analyze the potential effectiveness of the reader requirement in general as well as at these facilities.

DATES: Comments and related material must be received by the Coast Guard on or before January 5, 2023.

ADDRESSES: You may submit comments identified by docket number USCG–2022–0052 using the Federal Decision Making Portal at *http://www.regulations.gov.* See the ''Public Participation and Request for Comments'' portion of the **SUPPLEMENTARY INFORMATION** section for further instructions on submitting comments.

FOR FURTHER INFORMATION CONTACT: For information about this document or technical inquiries, call or email Lieutenant Commander Jeffrey Bender, U.S. Coast Guard; telephone 202–372–1114; email *Jeffrey.M.Bender@uscg.mil.* General information and press inquiries: Contact Chief Warrant Officer 3 Kurt Fredrickson, U.S. Coast Guard; telephone (202) 372–4619; email *Kurt.N.Fredrickson@uscg.mil.*

SUPPLEMENTARY INFORMATION:

Table of Contents for Preamble

I. Public Participation and Request for Comments

The Coast Guard views public participation as essential to effective rulemaking, and will consider all comments and material received during the comment period. Your comment can help shape the outcome of this rulemaking. If you submit a comment, please include the docket number for this rulemaking, indicate the specific section of this document to which each comment applies, and provide a reason for each suggestion or recommendation.

Submitting comments. We encourage you to submit comments through the Federal Decision Making Portal at *https://www.regulations.gov.* To do so, go to *https://www.regulations.gov,* type USCG–2022–0052 in the search box and click ''Search.'' Next, look for this document in the Search Results column, and click on it. Then click on the Comment option. If you cannot submit your material by using *https://www.regulations.gov,* call or email the person in the **FOR FURTHER INFORMATION CONTACT** section of this proposed rule for alternate instructions.

Viewing material in docket. To view documents mentioned in this proposed rule as being available in the docket, find the docket as described in the previous paragraph, and then select ''Supporting & Related Material'' in the Document Type column. Public comments will also be placed in our online docket and can be viewed by following instructions on the *https://www.regulations.gov* Frequently Asked Questions web page. That FAQ page also explains how to subscribe for email alerts that will notify you when comments are posted or if a final rule is published. We review all comments received, but we will only post comments that address the topic of the proposed rule. We may choose not to post off-topic, inappropriate, or duplicate comments that we receive.

Personal information. We accept anonymous comments. Comments we post to *https://www.regulations.gov* will include any personal information you have provided. For more about privacy and submissions to the docket in response to this document, see DHS's eRulemaking System of Records notice (85 FR 14226, March 11, 2020).

Public meeting. We do not plan to hold a public meeting, but we will consider doing so if we determine from public comments that a meeting would be helpful. We would issue a separate **Federal Register** notice to announce the date, time, and location of such a meeting.

For information on facilities or services for individuals with disabilities or to request special assistance at the public meeting, call or email the person listed in the **FOR FURTHER INFORMATION CONTACT** section of this document.

II. Abbreviations

2016 TWIC Reader final rule Transportation Worker Identification Credential (TWIC)—Reader Requirements'' final rule published August 23, 2016
2020 delay rule ''TWIC-Reader Requirements; Delay of Effective Date'' final rule published March 9, 2020
ANPRM Advance notice of proposed rulemaking
CAP Corrective Action Plan
CDC Certain Dangerous Cargoes
CFR Code of Federal Regulations
COVID–19 Coronavirus disease, 2019
DHS Department of Homeland Security
FR Federal Register
FSP Facility Security Plan
HSOAC Homeland Security Operational Analysis Center
MSRAM Maritime Security Risk Analysis Model
MTSA Maritime Transportation Security Act of 2002
NPRM Notice of proposed rulemaking
OMB Office of Management and Budget
PIN Personal identification number
SAFE Port Act Security and Accountability for Every Port Act of 2006
§ Section
TSA Transportation Security Administration
TWIC Transportation Worker Identification Credential
U.S.C. United States Code

III. Regulatory History

Pursuant to the Maritime Transportation Security Act of 2002 (MTSA),[1] and in accordance with the Security and Accountability for Every Port Act of 2006 (SAFE Port Act),[2] the electronic inspection of Transportation Worker Identification Credentials (TWIC) is required inside secure areas on certain vessels and facilities in the United States. Specifically, the SAFE Port Act required that the Secretary put into effect regulations that require the deployment of electronic transportation security card readers.[3] To implement this requirement in an effective manner, the Coast Guard undertook a series of regulatory actions culminating in a requirement to implement electronic TWIC inspection at certain high-risk vessels and facilities regulated under MTSA.

On May 22, 2006, the Coast Guard and the Transportation Security Administration (TSA) jointly published a notice of proposed rulemaking (NPRM) entitled ''Transportation Worker Identification Credential (TWIC) Implementation in the Maritime Sector; Hazardous Materials Endorsement for a Commercial Driver's License.'' [4] After considering comments on the NPRM, the Coast Guard and TSA published the final rule on January 25, 2007, also entitled ''Transportation Worker Identification Credential (TWIC) Implementation in the Maritime Sector; Hazardous Materials Endorsement for a Commercial Driver's License.'' [5] This final rule set forth the requirement, among others, that all persons allowed unescorted access to secure areas in MTSA-regulated vessels and facilities were required to possess a TWIC card. It did not, however, mandate that the TWIC card be read with an electronic reader. The card could be verified by visual inspection alone, without making use of the electronic security features built into the card.

Although the May 22, 2006 NPRM proposed certain TWIC reader requirements, after reviewing the public comments, the Coast Guard and TSA decided not to include those proposed requirements in the 2007 final rule. Instead, we addressed those requirements in a separate rulemaking and conducted a pilot program to address the feasibility of reader requirements before issuing a final rule. For a detailed discussion of the public comments and our responses to them, please refer to the January 25, 2007 final rule (Volume 72 of the **Federal Register** (FR), Page 3491).

On March 27, 2009, the Coast Guard published an advance notice of proposed rulemaking (ANPRM) on the topic of TWIC reader requirements.[6] The ANPRM discussed dividing vessels and facilities into three ''risk groups''—Risk Group A for the high-risk vessels and facilities, Risk Group B for medium-risk vessels and facilities, and Risk Group C for low-risk vessels and facilities. The ANPRM also considered different electronic inspection requirements for Risk Groups A and B, with no electronic inspection requirements for Risk Group C. On March 22, 2013, we published an NPRM that proposed the three risk groups (A,

[1] See Sec. 102 of Public Law 107–295 (November 25, 2002), codified as 46 U.S.C. 70105.

[2] See Sec. 104 of Public Law 109–347 (October 13, 2006).

[3] See 46 U.S.C. 70105(k)(3).

[4] 71 FR 29395 (May 22, 2006).

[5] 72 FR 3491 (January 25, 2007).

[6] 74 FR 13360 (March 27, 2009).

B, and C), but limited the proposed electronic TWIC inspection requirements to Risk Group A vessels and facilities only.[7]

On August 23, 2016, we published a final rule entitled ''Transportation Worker Identification Credential (TWIC)—Reader Requirements'' (''2016 TWIC Reader final rule'') that eliminated the three-risk group structure and required that the high-risk vessels and facilities (still referred to as Risk Group A) conduct electronic TWIC inspection for all personnel seeking unescorted access to secure areas of the vessel or facility; [8] Risk Group A facilities and vessels are defined within 33 CFR 104.263, 105.253 and 106.258.

The Congress also passed several laws that impacted implementation of the TWIC reader program. On December 16, 2016, the President signed the bill entitled ''Transportation Security Card Program Assessment.'' This law required, among other things, the Secretary of Homeland Security to commission a report reviewing the security value of the TWIC program by: (1) Evaluating the extent to which the TWIC program addresses known or likely security risks in the maritime and port environments; (2) evaluating the potential for a non-biometric credential alternative; (3) identifying the technology, business process, and operational impact of the TWIC card and readers in maritime and port environments; (4) assessing the costs and benefits of the Program, as implemented; and (5) evaluating the extent to which the Department of Homeland Security (DHS) has addressed the deficiencies of the TWIC program previously identified by the Government Accountability Office (GAO) and the DHS Office of the Inspector General (OIG). On August 2, 2018, the President followed up by signing the ''Transportation Worker Identification Credential Accountability Act of 2018,'' which prohibited the Coast Guard from implementing the TWIC Reader rule until at least 60 days after it submits the above report to the Congress.

On May 15, 2017, the Coast Guard received a petition for rulemaking requesting that it revise the final rule and impose electronic TWIC inspection requirements on only those vessels and facilities that engage in a maritime transfer of certain dangerous cargoes (CDC).[9] This is further discussed in Section IV. On June 22, 2018, we published a second NPRM, which proposed delaying the implementation of the 2016 TWIC Reader final rule.[10]

On March 9, 2020, the Coast Guard published a final rule entitled ''TWIC-Reader Requirements; Delay of Effective Date'' (''the 2020 delay rule'').[11] The 2020 delay rule extended the effective date of the 2016 rule only for Risk Group A facilities that handle CDC in bulk until May 8, 2023; the implementation date for facilities designated as Risk Group A due to their receiving of vessels certificated to carry more than 1,000 passengers remained unchanged and was implemented on August 23, 2018 (enforcement of the regulation was delayed due to the global COVID–19 pandemic until January 1, 2022).

In 2020, the Coast Guard commissioned the Homeland Security Operational Analysis Center (HSOAC), the Department's studies and analysis federally funded research and development center (FFRDC) operated by the RAND Corporation, to conduct an analysis to identify the population of facilities handling certain dangerous cargoes impacted by the 2016 TWIC Reader final rule, to develop a risk-consequence analysis for these facilities, and to conduct a benefit-cost analysis based on the information collected and analyzed during this subsequent study. The Rand Corporation analysis was received by the Coast Guard on July 29, 2022; the options for implementing the 2016 TWIC Reader final rule are currently being evaluated. While we evaluate the study results, to avoid the 2016 TWIC Reader rule going into effect and creating confusion and conflicts between its original requirements and the potential outcomes of the study, the Coast Guard will delay the original rule's implementation. The 2016 TWIC Reader final rule would remain in effect for facilities receiving vessels certificated to carry more than 1,000 passengers (33 CFR104.263, 105.253 and 106.258), as this proposed rule would not affect those facilities.

IV. Background

The 2016 TWIC Reader final rule established electronic TWIC reader regulations for certain high-risk vessels and MTSA-regulated facilities. Shortly thereafter, the chemical industry expressed concern that the final rule significantly expanded the scope of the 2013 NPRM, and requested that the Coast Guard narrow the classes of chemical facilities that would be subject to the enhanced security requirements. An industry association representing terminal companies nationwide then initiated litigation against the Department of Homeland Security (DHS) in 2017, claiming that the 2016 TWIC Reader final rule violated the Administrative Procedure Act (APA).[12] However, the court dismissed the action, holding that the issue was not ripe for adjudication because Congress passed legislation delaying the implementation of the final rule, and there was a likelihood that Congress or the Coast Guard might amend or replace the regulation.[13]

In June 2020, DHS published the Coast Guard's corrective action plan (CAP) entitled *Corrective Action Plan from the Assessment of the Risk Mitigation Value of the Transportation Worker Identification Credential*.[14] The CAP identified the need to conduct a risk analysis over the next 3 years in order to identify all facilities handling CDC and analyze the need for TWIC readers.

In September 2020, the Coast Guard again commissioned the HSOAC, operated by the RAND Corporation, to conduct a subsequent analysis to identify the population of facilities handling CDC impacted by the 2016 TWIC Reader final rule, to develop a risk-consequence analysis for these facilities, and to conduct a benefit/cost analysis.

V. Discussion of the Proposed Rule To Delay the Effective Date

In this NPRM, we propose to delay the effective date for facilities that handle CDC in bulk for 3 years from the original delay expiration date of May 8, 2023 to May 8, 2026. These facilities would not need to install electronic TWIC readers at least until the new implementation date. 2016 TWIC Reader final rule would remain in effect for facilities receiving vessels certificated to carry more than 1,000 passengers, as this proposed rule would not affect those facilities. This proposed rule would delay the implementation of TWIC readers for facilities that handle CDC in bulk so the Coast Guard can accurately determine the affected population through an analysis by the HSOAC, which would measure and assess potential risks of CDC, including

[7] 78 FR 17781 (March 22, 2013).

[8] 81 FR 57651.

[9] See Docket number USCG–2017–0447, available at *www.regulations.gov.*

[10] TWIC-Reader Requirements; Delay of Effective Date, 83 FR 29067 (June 22, 2018).

[11] 85 FR 13493.

[12] *Int'l Liquid Terminals Ass'n* v. *U.S. Dep't of Homeland Sec.*, No. 1:18–cv–00467, 2018 WL 8667001, at *1 (E.D. Va., Sept. 17, 2018).

[13] *Id.* at *2.

[14] A copy of the study is available in the docket for this rule. *Corrective Action Plan from the Assessment of the Risk Mitigation Value of the Transportation Worker Identification Credential; Report to Congress, June 2020.*

the types of CDC, population density within a certain distance of the facility and other risk and consequence aspects.

This proposed rule would allow the industry to provide further input on the implementation of the 2016 TWIC Reader final rule, and would provide additional time so that facility owners and operators can plan accordingly for implementation. We invite your comments on the proposed second delay of the 2016 TWIC Reader final rule we have reflected in our proposed regulatory text of an additional 3 years. We also realize that HSOAC study recommendations, and other relevant matters presented, may require the Coast Guard to possibly delay the effective date for more than three additional years and invite comments on possibly extending the delay through as late as May 8, 2029.

VI. Regulatory Analyses

This rulemaking would further delay the effective date for three types of facilities affected by the 2016 TWIC Reader final rule. Specifically, these are: (1) facilities that handle CDC in bulk, but do not transfer those cargoes to or from a vessel; (2) facilities that handle CDC in bulk and do transfer those cargoes to or from a vessel; and (3) facilities that receive vessels carrying CDC in bulk, but do not, during that vessel-to-facility interface, transfer those bulk cargoes to or from said vessels. The current effective date of the 2016 rule for these facilities is May 8, 2023, which was established by the 2020 delay rule. With this proposed rule, we would delay the effective date for facilities that handle CDC in bulk by an additional 3 years, until May 8, 2026.

Below, we provide an updated Regulatory Analyses of the 2016 TWIC Reader final rule that presents the impacts of delaying the effective date of the final rule for the three types of Risk Group A facilities defined in the preceding paragraph. For this updated analysis, we estimated the impact of delaying the final rule by calculating the 10-year cost of this proposed rule where only certain facilities will incur costs starting in year 4, and no facilities will incur costs in the first 3 years, in order to compare it to the 10-year cost presented in the Regulatory Impact Analyses (RIA) for the 2016 TWIC Reader final rule. We then calculated the difference between the two costs to estimate the impact, which is a net cost savings, of this proposed rule.

A. Regulatory Planning and Review

Executive Orders 12866 (Regulatory Planning and Review) and 13563 (Improving Regulation and Regulatory Review) direct agencies to assess the costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety effects, distributive impacts, and equity). Executive Order 13563 emphasizes the importance of quantifying costs and benefits, reducing costs, harmonizing rules, and promoting flexibility. This proposed rule is a significant regulatory action under section 3(f) of Executive Order 12866. The Office of Management and Budget (OMB) has reviewed it under that Order. It requires an assessment of potential costs and benefits under section 6(a)(3) of Executive Order 12866. In accordance with OMB Circular A–4, we have prepared an accounting statement showing the classification of impacts associated with this final rule.

TABLE 1—OMB A–4 ACCOUNTING STATEMENT 2022–2032 PERIOD OF ANALYSIS

[2020 Dollars]

	Primary estimate		Source
	Benefits		
Annualized monetized benefits	....	7% 3%	RA
Annualized quantified, but unmonetized, benefits	None.		RA
Unquantifiable Benefits	For facilities with a delayed compliance, final rule will postpone the enhanced benefits of electronic TWIC Inspection.		RA
Cost Savings			
Annualized monetized costs ($ Mil)	($5.4) ($3.6)	7% 3%	RA RA
Annualized quantified, but unmonetized, costs	None.		RA
Qualitative (un-quantified) cost savings	The proposed rule would delay the cost to retrieve or replace lost PINs for use with TWICs for the facilities with delayed implementation.		RA
Transfers			
Annualized monetized transfers: "on budget"	Not calculated.		RA
From whom to whom?			RA
Annualized monetized transfers: "off-budget"	None.		
From whom to whom?	None.		

TABLE 1—OMB A–4 ACCOUNTING STATEMENT 2022–2032 PERIOD OF ANALYSIS—Continued

[2020 Dollars]

Miscellaneous Analyses/Category		
Effects on Tribal, State, and/or local governments	None.	
Effects on small businesses	Proposed rule would not have a significant economic impact on a substantial number of small entities.	RA
Effects on wages	None.	
Effects on growth	No determination.	

This rulemaking would further delay the effective date for certain facilities—that is, all facilities that handle certain CDC in bulk—affected by the 2016 TWIC Reader final rule. The current effective date of the 2016 rule for these facilities is May 8, 2023, which was established by the first effective date 2020 delay rule, published March 9, 2020. With this proposed rule, we would delay the effective date for these facilities for 3 years from the original delay expiration date of May 8, 2023, to May 8, 2026, but invite comments as well on possibly extending the delay to as late as May 8, 2029.

This proposed rule would delay the implementation of the 2016 TWIC Reader final rule by 3 years (May 8, 2026, or later) for facilities that handle CDC in bulk but do not transfer it to or from a vessel, facilities that handle CDC in bulk and do transfer those cargoes to or from a vessel, and facilities that receive vessels carrying bulk CDC but, during that vessel-to-facility interface, do not transfer bulk CDC to or from the vessel. This proposed rule does not modify any of the regulatory requirements under the 2016 TWIC reader final rule. We did not revise our fundamental methodologies or key assumptions for the 2016 TWIC Reader final rule RIA.[15]

In the 2016 TWIC Reader final rule RIA, we estimated that 525 facilities and 1 vessel out of the MTSA-regulated entities (13,825 vessels and more than 3,270 facilities) would have to comply with the final rule's electronic TWIC inspection requirements using the Maritime Security Risk Analysis Model (MSRAM's) risk-based tiered approach.[16] Using data from MSRAM, we estimate that this proposed rule would delay the implementation of the final rule for 370 of the 525 affected Risk Group A facilities by 3 years, while the remaining 155 facilities and 1 vessel were required to implement the final rule requirements by June 8, 2020. These 370 facilities are those that handle bulk CDC, but do not transfer it to or from a vessel, facilities that handle CDC in bulk and do transfer those cargoes to or from a vessel, and facilities that receive vessels carrying bulk CDC but, during the vessel-to-facility interface, do not transfer the bulk CDC to or from the vessel. We did not include these facilities in our MSRAM risk analysis for the 2016 final rule or in the 2016 final rule's RIA, as, we could not determine the number of those facilities at the time, and we did not include them in our cost estimates for this proposed rule. The number of actual facilities that meet the criteria, and that fall into the above category, will not be known until after an additional study is conducted to improve the risk methodology and determine the new risk groups. The final count of facilities will most likely be similar, but not identical to the cited 370 facilities. Therefore, the USCG is using its discretion to delay the implementation of the TWIC reader rule on those 370 facilities until a more accurate population estimate can be established. Future regulatory analyses will update these estimates once the commissioned risk study is complete and the Coast Guard has assessed which CDC facilities fall within the level or risk that is deemed appropriate to require a TWIC reader. We updated our final rule cost estimates from 2012 to 2020 based on Gross Domestic Product (GDP) deflator data from the U.S. Bureau of Economic Analysis (BEA).[17] The GDP deflator is a measure of the change in price of domestic goods and services purchased by consumers, businesses, and the Government.

Table 2 summarizes the costs and benefits of the 2020 Final Rule to Delay the TWIC Reader Final rule, as well as this proposed rule, which would extend the delay from the 2020 Final Rule. We do not anticipate any new costs to industry if the final rule is implemented, because this proposed rule would not change the applicability of the 2016 final rule or any subsequent amendments thereof. This proposed rule would result in no other changes to the 2016 TWIC Reader final rule. There is no impact to the one previously affected vessel and 155 MTSA facilities that complied with the TWIC rule as of June 8, 2020. Because this proposed rule would extend the delay on implementation of the final rule by three years for 370 facilities, it would result in cumulative cost savings to industry and the Government of $37.84 million (discounted at seven percent) over a 10-year period of analysis ($152.95 million minus $115.12 million). At a seven percent discount rate, we estimate the total annualized cost savings to be $5.39 million ($21.78 million minus $16.39 million).

[15] Available in the docket; docket number USCG–2007–28915–0231.

[16] See Table 2.8 on page 26 of the 2016 TWIC Reader final rule Regulatory Analysis for the estimate of 525 facilities, and Table 2.1 on page 23 for the estimate of 1 vessel.

[17] For consistency across rulemaking analyses, we are using the annual Implicit Price Deflators for Gross Domestic Product (BEA National Income and Product Accounts (NIPA) Table 1.1.9) values updated in 2021, accessed by the Coast Guard through the BEA's publicly available data sets. The NIPA tables can be found at: *https://apps.bea.gov/iTable/index_nipa.cfm.*

TABLE 2—SUMMARY OF COSTS SAVING AND CHANGE IN BENEFITS: 2020 FINAL RULE TO DELAY TWIC FINAL RULE TO NPRM TO DELAY THE FINAL RULE

Category	2020 TWIC reader final delay rule (2020 dollars)	Proposed rule to delay 2016 TWIC reader final rule (2020 dollars)
Affected Population	370 facilities that handle bulk CDC, and an unknown number of facilities that receive vessels carrying bulk CDC but, during that vessel-to-facility interface, do not transfer bulk CDC to or from the vessel.	370 facilities that handle bulk CDC, but do not transfer it to or from a vessel and that handle bulk CDC and do transfer such cargoes to or from a vessel (to comply by May 8th, 2026). The proposed rule would also apply to facilities that receive vessels carrying bulk CDC but, during that vessel-to-facility interface, do not transfer bulk CDC to or from the vessel. However, the number of these facilities cannot be determined at this time and will not be known until after an additional study is conducted to improve the risk methodology and determine the new risk groups to comply by May 8, 2026. *No change from final rule*.
Costs to Industry and Government ($ millions, 7% discount rate).	Industry: $21.76 (annualized) Government: $0.015 (annualized) Both: $21.78 (annualized) Industry: $152.85 (10-year) Government: $0.103 (10-year) Both: $152.95 (10-year)	Industry: $16.38 (annualized). Government: $0.008 (annualized). Both: $16.39 (annualized). Industry: $115.06 (10-year). Government: $0.059 (10-year). Both: $115.12 (10-year).
Change in Costs (Qualitative).	Time to retrieve or replace lost personal identification numbers (PINs) for use with TWICs.	The proposed rule would delay the cost to retrieve or replace lost PINs for use with TWICs for the facilities with delayed implementation.
Change in Benefits (Qualitative).	Enhanced access control and security at U.S. maritime facilities and on-board U.S.-flagged vessels. Reduction of human error when checking identification and manning access points.	Delaying enhanced access control and security for the facilities with delayed implementation. Delaying the reduction of human error when checking identification and manning access points for the facilities with delayed implementation.
Total Cost Savings ($ millions, 7% discount rate).	*Annualized*	Industry: $5.38 (annualized). Government: $0.006 (annualized). Total: $5.39 (annualized).
	10-Year	Industry: $37.79 (10-year). Government: $0.04 (10-year). Total: $37.84 (10-year).

Methodology

Final Rule Costs Inflated to 2020 Dollars

As shown in table 1, we updated the annualized cost of the 2016 TWIC Reader final rule from 2012 dollars to 2020 dollars (over a 10-year period), then adjusted the population count to be consistent with the smaller affected population. With adjustments, the cost of the rule (over a 10-year period) is approximately $21.76 million, at a seven percent discount rate. We performed this update to compare those costs to this proposed rule's total industry costs on the same basis. The following costs take into account revisions made in the 2020 delay rule of March 9, 2020 that corrected mathematical errors from the 2016 TWIC Reader rule which, impacted the estimated average number of readers per access point, and the average installation and infrastructure costs for facilities. Although we have updated our analysis from the NPRM to reflect these changes, this did not modify the methodology of our RA, other than to account for the reduced population that is affected by this NPRM.

We used an inflation factor from the annual GDP deflator data. We calculated the inflation factor of 1.136 by modifying the deflator base year to 2020 (GDP deflator = 100 at 2020 prices) and dividing the annual 2020 index number (100) by the annual 2012 index number (88). We then applied this inflation factor to the costs for vessels and additional costs, which include additional delay costs, travel costs, and the cost to replace TWIC readers that fail (Table 4.38 of the final rule RIA).

For facilities, we applied this inflation factor to the total cost-by-cost component (table 4.17 of the 2016 TWIC Reader final rule) because the proposed rule would apply to only some of these cost elements. Facility costs include capital costs, maintenance costs, and operational costs. Capital costs consist of the cost to purchase and install TWIC readers, as well as the cost to fully replace TWIC readers 5 years after the original installation. Maintenance costs account for the costs to maintain TWIC readers every year after the original installation. Operational costs include costs that occur only at the time of the TWIC reader installation, such as those for amending security plans, creating a recordkeeping system, and initial training. Operational costs also include ongoing costs, such as those for keeping and maintaining records, downloading the canceled card list, and ongoing annual training.

Proposed Rule Costs

This proposed rule would delay the effective date of the final rule by three years (until May 8, 2026) for 370 facilities that handle bulk CDC, but do not transfer it to or from a vessel and facilities that handle CDC in bulk, and do transfer those cargoes to or from a vessel, and an undetermined number of facilities that receive vessels carrying bulk CDC, but do not transfer it to or from the vessel during that vessel-to-facility interface. To allow for a consistent comparison between the baseline estimates and the costs of this proposed rule, we maintain the assumption from the 2016 TWIC Reader final rule RA that 50 percent of facilities will comply for each of the two final years preceding the final implementation date. Therefore, for this NPRM, we assume that 50 percent of facilities with a three-year implementation delay will comply in May of year 3, and 50 percent of facilities with a three-year implementation delay will comply in year 4. We maintain this assumption to provide a consistent comparison between the baseline cost estimates presented in the 2016 TWIC Reader final rule, and the costs of this rule.

The costs are separated into three categories (2020 dollars): (1) capital costs of which the initial average capital cost per facility is $278,630; (2) maintenance costs, of which the average annual cost incurred per facility for the first year is $4,290; and (3) operational costs, which on average per facility are $8,594. The total undiscounted costs for the first year of operation on average per facility is $287,220. After the initial five-year period of use, TWIC readers may need to be replaced, our assumption is that all readers will need to be replaced at five-year intervals, although it is likely that this will not be the case and that only a percent of readers will need replacement. The average cost per facility to replace its TWIC readers is $4,296.

To estimate the capital costs in a given year, we multiplied the total baseline capital costs for all facilities by the percentage of facilities incurring costs in a given year. Because maintenance costs are not incurred until the year after the TWIC readers are installed, we calculated the proposed rule maintenance costs in a given year by multiplying the total baseline costs for all facilities by the percentage of facilities complying in the previous year. We estimated operational costs in a similar manner, multiplying total operational costs by the percentage of facilities complying in a given year. Table 3 presents the total cost to facilities under this proposed rule.

TABLE 3—TOTAL COST FOR FACILITIES FROM PARTIALLY DELAYING THE EFFECTIVE DATE OF THE 2016 TWIC READER FINAL RULE

[Millions 2020 Dollars]

Year	Number of new facilities	Total number of facilities	Capital costs	Maintenance costs	Operational costs	Undiscounted total
1	0	0	$0.00	$0.00	$0.00	$0.00
2	0	0	0.00	0.00	0.00	0.00
3	0	0	0.00	0.00	0.00	0.00
4	185	185	51.64	0.00	1.59	53.23
5	185	370	52	0.80	2.13	54.57
6	0	370	0.00	1.59	1.07	2.66
7	0	370	0.00	1.59	1.07	2.66
8	0	370	0.00	1.59	1.07	2.66
9	0	370	7.96	2.26	1.07	11.29
10	0	370	7.96	2.26	1.07	11.29
Total			119.21	10.09	9.07	138.37

Note: Totals may not sum due to rounding.

Table 4 summarizes the total costs to industry of this proposed rule in 2020 dollars. This proposed rule would not impact the compliance schedule for vessels, therefore these costs remain unchanged from the baseline. We calculated the additional costs by multiplying the totals in table 2 by the percentage of facilities complying within a given year and phasing them in over two years. Over ten years, we estimate the annualized cost to industry to be $16.38 million at a seven percent discount rate.

TABLE 4—TOTAL INDUSTRY COST UNDER THE 2022 PROPOSED RULE PARTIALLY DELAYING THE EFFECTIVE DATE OF THE 2016 TWIC READER RULE

[Millions, 2020 Dollars]

Year	Facility	Vessel	Additional costs *	Undiscounted	7%	3%
1	$0.00	$0.000	$0.00	$0.00	$0.00	$0.00
2	0.00	0.000	0.00	0.00	0.00	0.00
3	0.00	0.000	0.00	0.00	0.00	0.00
4	53.23	0.000	1.69	54.92	41.90	48.80
5	54.57	0.000	4.78	59.35	42.31	51.19
6	2.66	0.000	4.78	7.45	4.96	6.24
7	2.66	0.000	4.78	7.45	4.64	6.05
8	2.66	0.000	4.78	7.45	4.33	5.88
9	11.29	0.000	4.78	16.07	8.74	12.32
10	11.29	0.000	4.78	16.07	8.17	11.96
Total	138.37	0.000	30.38	168.75	115.06	142.44
Annualized					16.38	16.70

* These costs include additional delay, travel, and TWIC replacement costs due to TWIC failures.
Totals may not sum due to rounding.

Table 5 presents the estimated change in total costs to industry from delaying the implementation of the 2016 TWIC Reader final rule by three years (until May 8, 2026) for facilities that handle bulk CDC, but do not transfer it to or from a vessel, facilities that handle CDC in bulk, and do transfer those cargoes to or from a vessel, and facilities that receive vessels carrying bulk CDC, but do not transfer it to or from the vessel during that vessel-to-facility interface. We estimated an annualized cost savings to industry of $3.60 million at a seven percent discount rate.

TABLE 5—TOTAL CHANGE IN INDUSTRY COST FROM THE 2020 TWIC FINAL DELAY RULE TO THE 2022 NPRM PARTIALLY DELAYING THE EFFECTIVE DATE OF FINAL RULE

[Millions, 2020 Dollars]

Total 10-year cost (not discounted)	Total 10-year cost (discounted)		Annualized cost	
	7%	3%	7%	3%
2020 TWIC Final Delay Reader Rule: $192.21	$152.85	$173.16	$21.76	$20.30
NPRM to Delay Final Rule by 3 years: $168.75	115.06	142.44	16.38	16.70
Change (Cost Savings): ($23.46)	(37.79)	(30.72)	(5.38)	(3.60)

Qualitative Costs

Qualitative costs are as shown in table 1. This proposed rule would delay the cost to retrieve or replace lost PINs for use with TWICs for the facilities with delayed implementation.

Government Costs

We expect that this proposed rule would also generate a cost savings to the Government from delaying the review of the revised security plans for 370 Risk Group A facilities that handle bulk CDC, but do not transfer it to or from a vessel, and facilities that receive vessels carrying bulk CDC. There is no change in cost to the Government resulting from TWIC inspections, because inspections are already required under MTSA, and the TWIC reader requirements do not modify these requirements. As such, there is no additional cost to the Government.

To estimate the cost to the Government, we followed the same approach as the industry cost analysis and adjusted the cost estimate presented in the final rule RIA from 2012 dollars to 2020 dollars. For the government analysis, we used the fully loaded 2020 wage rate for an E–5 level staff member, $54 per hour, from Commandant Instruction 7310.1U: Reimbursable Standard Rates, in place of the 2012 wage of $49 per hour.[18] We then followed the calculations outlined on page 72 of the final rule Regulatory Analysis to estimate a government cost of $56,700 in years four and five ($54 × 4 hours per review × 262.5 plans).

Table 6 presents the annualized baseline government costs of $14,596 at a seven percent discount rate.

TABLE 6—TOTAL GOVERNMENT COST UNDER 2020 TWIC READER FINAL DELAY RULE

[2020 Dollars]

Year	Cost of facility security plan (FSP)	7%	3%
1	$0	$0	$0
2	0	0	0
3	0	0	0
4	39,960	30,485	35,504
5	39,960	28,491	34,470
6	0	0	0
7	0	0	0
8	0	0	0
9	0	0	0
10	0	0	0
Total	79,920	58,976	69,974
Annualized	....	8,397	8,203

Table 7 presents the government cost under the proposed rule. We estimated the annualized government cost to be $8,397 at a seven percent discount rate. To estimate government costs in year 4 and year 5, we used the same approach as the baseline cost estimates.[19]

[18] Because the Coast Guard is not delaying the implementation schedule for vessels, the proposed rule would have no impact on the costs associated with vessel security plans, and, therefore, we did not include them in this RA.

[19] We calculated the total cost in year 1 as 4 hours × $54 × 202 FSPs; the total cost in year 2 as 4 hours × $54 × 201 FSP and the total cost in years 3 and 4, as 4 hours × $54 × 61 FSPs.

TABLE 7—TOTAL GOVERNMENT COST UNDER THE 2022 NPRM PARTIALLY DELAYING THE EFFECTIVE DATE OF THE 2016 FINAL RULE, RISK GROUP A

[2020 Dollars]

Year	Cost of FSP	7%	3%
1	$0	$0	$0
2	0	0	0
3	0	0	0
4	39,960	30,485	35,504
5	39,960	28,491	34,470
6	0	0	0
7	0	0	0
8	0	0	0
9	0	0	0
10	0	0	0
Total	79,920	58,976	69,974
Annualized	....	8,397	8,203

Table 8 presents the estimated change in government costs from delaying the implementation of the 2016 TWIC Reader final rule by three years (until May 8, 2026) for facilities that handle bulk CDC, but do not transfer it to or from a vessel, and facilities that receive vessels carrying bulk CDC, but do not transfer it to or from the vessel during that vessel-to-facility interface. We estimated an annualized cost savings to the Government of $6,199 at a seven percent discount rate.

TABLE 8—TOTAL CHANGE IN GOVERNMENT COST FROM THE 2020 FINAL RULE TO DELAY TWIC TO THE 2022 NPRM DELAYING THE EFFECTIVE DATE OF THE 2016 TWIC FINAL RULE

[2020 Dollars]

Total cost (not discounted)	Total cost (discounted)		Annualized cost	
	7%	3%	7%	3%
2016 TWIC Reader Final Rule: $79,920	$102,515	$108,494	$14,596	$12,719
NPRM to Delay Final Rule by 3 years: $113,400	58,976	69,974	8,397	8,203
Change: $33,480	(43,538)	(38,520)	(6,199)	(4,516)

Change in Benefits

As noted, this proposed rule would delay the effective date of the 2016 TWIC Reader final rule requirement for three categories of facilities: (1) Facilities that handle bulk CDC, but do not transfer it to or from a vessel; (2) facilities that handle CDC and do transfer such cargoes to or from a vessel; and (3) facilities that receive vessels carrying bulk CDC, but do not transfer bulk CDC to or from the vessel during that vessel-to-facility interface. The facilities for which the 2016 TWIC Reader final rule would be delayed will not realize the enhanced benefits of electronic inspection, such as the increased protection against individuals who do not hold valid TWICs being granted unescorted access, enhanced verification of personal identity, and a reduction in potential vulnerabilities until May 8, 2026.

In addition, the proposed rule would delay the cost to retrieve or replace lost PINs for use with TWICs for the facilities with delayed implementation. This is an unquantified cost savings which would accrue to individual mariners and the Coast Guard.

B. Small Entities

Under the Regulatory Flexibility Act, Title 5 of the United States Code (U.S.C.), Sections 601–612, we have considered whether this proposed rule would have a significant economic impact on a substantial number of small entities. 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 will delay the effective date of the 2016 TWIC Reader final rule from May 8, 2023 until May 8, 2026 for facilities that handle CDC in bulk. We estimate that, consistent with past and present analyses, 370 facilities will experience cost savings. We estimate these facilities would experience an annualized cost savings of approximately $9,800 (with a seven percent discount rate), and that on average each entity owns two facilities and would save approximately $19,600. We calculate that approximately two percent of the small entities impacted by this proposed 2022 delay NPRM would have a cost savings that is greater than one percent but less than three percent of their annual revenue. The other 98 percent would have a cost savings that is less than one percent of their annual revenue.

Given this information, the Commandant of 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.

If you think that your business, organization, or governmental jurisdiction qualifies as a small entity and that this proposed rule would have a significant economic impact on it, please submit a comment to the docket at the address listed in the **ADDRESSES** section of this preamble. In your comment, explain why you think it qualifies and how and to what degree this proposed rule would economically affect it.

C. Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996, Public Law 104–121, we want to assist small entities in understanding this proposed rule so that they can better evaluate its effects on them and participate in the rulemaking. If this proposed rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please contact the person in the **FOR FURTHER INFORMATION CONTACT** section of this NPRM. The Coast Guard will not retaliate against small entities that question or complain about this proposed rule or any policy or action of the Coast Guard.

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).

D. Collection of Information

This proposed rule would call for no new collection or revision of information under the Paperwork Reduction Act of 1995, 44 U.S.C. 3501–3520.

E. Federalism

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 proposed rule under Executive Order 13132 and have determined that it is consistent with the fundamental federalism principles and preemption requirements described in Executive Order 13132. Our analysis follows.

This proposed rule would delay the implementation of existing regulations that create a risk-based set of security measures for MTSA-regulated facilities. Based on this analysis, each facility is classified according to its risk level, which then determines whether the facility will be required to conduct electronic TWIC inspection. As this proposed rule would not impose any new requirements, but simply delay the implementation of existing requirements, it would not have a preemptive impact. Please refer to the Coast Guard's federalism analysis in the 2016 TWIC Reader Final Rule (81 FR 57651, 57706) for additional information.

While it is well settled that States may not regulate in categories in which Congress intended the Coast Guard to be the sole source of a vessel's obligations, States and local governments have traditionally shared certain regulatory jurisdiction over waterfront facilities. Therefore, MTSA standards contained in Title 33 of the Code of Federal Regulations (CFR) part 105 (Maritime security: Facilities) are not preemptive of State or local law or regulations that do not conflict with them (that is, they would either actually conflict or would frustrate an overriding Federal need for uniformity).

The Coast Guard recognizes the key role that State and local governments may have in making regulatory determinations. Additionally, for rules with federalism implications and preemptive effect, Executive Order 13132 specifically directs agencies to consult with State and local governments during the rulemaking process. If you believe this rule has implications for federalism under Executive Order 13132, please contact the person listed in the **FOR FURTHER INFORMATION** section of this preamble.

F. Unfunded Mandates

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 Tribal, State, or local government, in the aggregate, or by the private sector of $100 million (adjusted for inflation) or more in any one year. Although this proposed rule would not result in such expenditure, we discuss the effects of this NPRM elsewhere in this preamble.

G. Taking of Private Property

This proposed rule would not cause a taking of private property or otherwise have taking implications under Executive Order 12630 (Governmental Actions and Interference with Constitutionally Protected Property Rights).

H. Civil Justice Reform

This proposed rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, (Civil Justice Reform) to minimize litigation, eliminate ambiguity, and reduce burden.

I. Protection of Children

We have analyzed this proposed rule under Executive Order 13045 (Protection of Children from Environmental Health Risks and Safety Risks). This proposed rule is not an economically significant rule and will not create an environmental risk to health or risk to safety that might disproportionately affect children.

J. Indian Tribal Governments

This proposed rule does not have tribal implications under Executive Order 13175 (Consultation and Coordination with Indian Tribal Governments) because it would 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.

K. Energy Effects

We have analyzed this proposed rule under Executive Order 13211 (Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use). We have determined that it is not a ''significant energy action'' under that order because although it is a ''significant regulatory action'' under Executive Order 12866, it is not likely to have a significant adverse effect on the supply, distribution, or use of energy, and the Administrator of OMB's Office of Information and Regulatory Affairs has not designated it as a significant energy action.

L. Technical Standards

The National Technology Transfer and Advancement Act, codified as a note to 15 U.S.C. 272, directs agencies to use voluntary consensus standards in their regulatory activities unless the agency provides Congress, through OMB, with an explanation of why using these standards would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* specifications of materials, performance, design, or operation; test methods; sampling procedures; and related management systems practices) that are developed or adopted by voluntary consensus standards bodies.

This proposed rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

M. Environment

We have analyzed this proposed rule under Department of Homeland Security Management Directive 023–01, Rev. 1, associated implementing instructions, and Environmental Planning COMDTINST 5090.1 (series), which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (42 U.S.C. 4321–4370f), and have made a preliminary determination that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. A preliminary Record of Environmental Consideration supporting this determination is available in the docket where indicated under the ''Public Participation and Request for Comments'' section of this preamble. This proposed rule would be categorically excluded under paragraph L54 of Appendix A, Table 1 of DHS Instruction Manual 023–01(series). Paragraph L54 pertains to regulations that are editorial or procedural. We seek any comments or information that may lead to the discovery of a significant environmental impact from this proposed rule.

List of Subjects in 33 CFR Part 105

Maritime security, Reporting and recordkeeping requirements, Security measures.

For the reasons listed in the preamble, the Coast Guard proposes to amend 33 CFR part 105 as follows:

PART 105—MARITIME SECURITY: FACILITIES

■ 1. The authority citation for part 105 continues is revised as follows:

Authority: 46 U.S.C. 70034, 70103, 70116; Sec. 811, Public Law 111–281, 124 Stat. 2905; 33 CFR 1.05–1, 6.04–11, 6.14, 6.16, and 6.19; Department of Homeland Security Delegation No. 00170.1, Revision No. 01.3.

■ 2. Amend § 105.253 by revising paragraphs (a)(2) through (4) to read as follows:

§ 105.253 Risk Group classifications for facilities.

(a) * * *

(2) Beginning May 8, 2026: Facilities that handle Certain Dangerous Cargoes (CDC) in bulk and transfer such cargoes from or to a vessel.

(3) Beginning May 8, 2026: Facilities that handle CDC in bulk, but do not transfer it from or to a vessel.

(4) Beginning May 8, 2026: Facilities that receive vessels carrying CDC in bulk but, during the vessel-to-facility interface, do not transfer it from or to the vessel.

* * * * *

Dated: November 30, 2022.

Linda Fagan,

Admiral, U.S. Coast Guard, Commandant.

[FR Doc. 2022–26493 Filed 12–5–22; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R07–OAR–2022–0880; FRL–10388–01–R7]

Air Plan Approval; MO; Marginal Nonattainment Plan for the St. Louis Area for the 2015 8-Hour Ozone Standard

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to approve a State Implementation Plan (SIP) revision submitted by the Missouri Department of Natural Resources (MoDNR) on September 8, 2021, and supplemented on April 8, 2022, as meeting the Marginal nonattainment area requirements for the 2015 8-hour ozone National Ambient Air Quality Standard (NAAQS or standard) for the Missouri portion of the St. Louis, MO–IL nonattainment area (''St. Louis area'' or ''area''). The EPA is proposing this action pursuant to the Clean Air Act (CAA or Act).

DATES: Comments must be received on or before January 5, 2023.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–R07–OAR–2022–0880 at *http://www.regulations.gov.* Follow the online instructions for submitting comments.

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received will 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 ''Written Comments'' heading of the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: Ashley Keas, Environmental Protection Agency, Region 7 Office, Air Quality Planning Branch, 11201 Renner Boulevard, Lenexa, Kansas 66219; telephone number: (913) 551–7629; email address: *keas.ashley@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document whenever ''we,'' ''us,'' or ''our'' is used, we mean EPA.

Table of Contents

I. Written Comments

Submit your comments, identified by Docket ID No. EPA–R07–OAR–2022–0880, at *https://www.regulations.gov.* Once submitted, comments cannot be edited or removed from *Regulations.gov*. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. 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.*

II. What is the background for this proposed action?

EPA has determined that ground-level ozone is detrimental to human health. On October 1, 2015, EPA promulgated a revised 8-hour ozone NAAQS of 0.070 parts per million (ppm). See 80 FR 65292 (October 26, 2015). Under EPA's regulations at 40 Code of Federal Regulations (CFR) part 50, the 2015 ozone NAAQS is attained in an area when the 3-year average of the annual fourth highest daily maximum 8-hour average concentration is equal to or less than 0.070 ppm, when truncated after the thousandth decimal place, at all ozone monitoring sites in the area. *See*

40 CFR 50.19 and appendix U to 40 CFR part 50.

Upon promulgation of a new or revised NAAQS, section 107(d)(1)(B) of the CAA requires EPA to designate as nonattainment any areas that are violating the NAAQS, based on the most recent 3 years of quality assured ozone monitoring data. On April 30, 2018, EPA designated the St. Louis, MO–IL bi-state area as Marginal nonattainment for the 2015 Ozone NAAQS (83 FR 25776). The area included Boles Township of Franklin County, St. Charles County, St. Louis County, and St. Louis City in Missouri, and Madison and St. Clair Counties in Illinois. As part of that same action, EPA designated Jefferson County and the remaining portion of Franklin County, in Missouri, and Monroe County in Illinois, as attainment/unclassifiable. On July 10, 2020, the District of Columbia Circuit Court remanded the Jefferson County, Missouri, and Monroe County, Illinois, designations (among other designations) to the EPA. The Court upheld EPA's designation of Boles Township as nonattainment and the remainder of Franklin County as attainment/unclassifiable. In response to the Court remand, the EPA revised the Jefferson County, Missouri, and Monroe County, Illinois designation to nonattainment on May 26, 2021 (86 FR 31438).

On October 7, 2022, the EPA published a final rulemaking including EPA's determination of whether areas designated as Marginal nonattainment for the 2015 8-hour ozone NAAQS attained by the applicable attainment date of August 3, 2021 (87 FR 60897). In that document, the EPA determined the St. Louis bi-state area, among other areas, failed to attain by the attainment date based on the monitoring data available as of the attainment date, for the 2018–2020 time period. In that time period, the highest design value in the St. Louis area was 0.071 ppm which is above the level of the standard, 0.70 ppm. As a result of EPA's determination that the St. Louis area failed to attain by the Marginal attainment date, the area is reclassified to Moderate nonattainment, effective November 7, 2022. Moderate nonattainment areas must attain by August 3, 2024 and submit a Moderate nonattainment area plan and its required elements by January 1, 2023. The CAA requirements applicable to Marginal ozone nonattainment areas continue to apply to Missouri despite the reclassification to Moderate. Missouri's submission to meet the Marginal ozone nonattainment area requirements is the subject of this action.

III. What is the EPA's analysis of Missouri's submission?

Section 172(c) of the CAA sets forth the basic requirements of air quality plans for states with nonattainment areas that are required to submit them pursuant to section 172(b). Subpart 2 of part D, which includes section 182 of the CAA, establishes specific requirements for ozone nonattainment areas depending on the areas' nonattainment classifications.

The St. Louis area was classified as Marginal under subpart 2 for the 2015 ozone NAAQS at the time of its nonattainment designation. At the time of Missouri's September 2021 SIP submission, the area was subject to the relevant requirements of subpart 1 contained in section 172(c) and section 176. Similarly, the area was subject to the subpart 2 requirements contained in section 182(a) (Marginal nonattainment area requirements). A thorough discussion of the requirements contained in section 172(c) and 182 can be found in the April 16, 1992, General Preamble for the Implementation of Title I of the CAA Amendments of 1990 (57 FR 13498) and the April 28, 1992 supplement (57 FR 18070).

As provided in subpart 2, for Marginal ozone nonattainment areas, the specific requirements of section 182(a) apply in lieu of the attainment planning requirements that would otherwise apply under section 172(c), including the attainment demonstration and reasonably available control measures (RACM) under section 172(c)(1), reasonable further progress (RFP) under section 172(c)(2), and contingency measures under section 172(c)(9).[1]

Section 172(c)(3) requires submission and approval of a comprehensive, accurate and current inventory of actual emissions. This requirement is superseded by the inventory requirement in section 182(a)(1) discussed below.

Section 172(c)(4) requires the identification and quantification of allowable emissions for major new and modified stationary sources in an area, and section 172(c)(5) requires source permits for the construction and operation of new and modified major stationary sources anywhere in the nonattainment area. The EPA most recently approved Missouri's New Source Review (NSR) program on August 11, 2022 (87 FR 49530).[2]

CAA section 172(b) requires states to submit SIPs meeting the requirements of section 172(c) no later than 3 years from the date of the nonattainment designation. For the St. Louis nonattainment area, the Marginal nonattainment area plan elements required under CAA section 172 and 182 were due August 3, 2021. Missouri submitted the requisite plan elements on September 8, 2021. In this action, the EPA is proposing to approve the September 8, 2021 submission from Missouri as meeting the relevant requirements of CAA section 172 and 182.

Section 182(a)(2)(C) requires states to implement a permitting program requiring permits for the construction and operation of new or modified major stationary sources anywhere in the nonattainment area. In its September 2021 submission, MoDNR confirms it has a fully-approved and fully-implemented Part D NSR permitting program for new major sources and significant modifications of existing sources enabled by SIP-approved state rule 10 Code of State Regulations (CSR) 10–6.060 *Construction Permits Required.* Missouri also notes it has been delegated full authority to implement its NSR program by the EPA.

Section 182(a)(3)(A) requires states to submit revised emission inventories every three years until the area is redesignated to attainment. Section 182(a)(3)(B) requires a revision to the SIP to require the owners or operators of stationary sources to annually submit emission statements documenting actual VOC and NO_X emissions. In its September 2021 submission, MoDNR committed to providing future updates to its emissions inventory at least once every 3 years to meet the requirement of section 182(a)(3)(A). To meet the requirement of section 182(a)(3)(B), the state certified that SIP-approved state rule 10 CSR 10–6.110 requires annual emissions statements from permitted sources in the state.

Section 182(a)(4) requires establishing a Marginal Area emission offset reduction ratio of 1.1:1 for VOC emissions. As noted in MoDNR's September 2021 SIP revision, the requirement for emission offset reductions is part of Missouri's NSR program and codified in the state's regulations at 10 CSR 10–6.060(7)(C)1. The corresponding offset ratio for each ozone area classification (*i.e.* 1.1:1 for Marginal) is found in the Federal code

[1] *See* 42 U.S.C. 7511a(a).

[2] In its August 2022 action, the EPA partially approved and partially disapproved Missouri's SIP revision related to state rule 10 CSR 10–6.060. In the August 2022 action, the EPA disapproved one provision related to voluntary permits and approved the remainder of the SIP revision. For purposes of this action, the EPA notes this partial disapproval does not affect the state's ability to continue implementation of its SIP-approved NSR program.

at 40 CFR 51.165(a)(9). Thus, Missouri has satisfied the CAA section 182(a)(4) requirement for Marginal Area Plan submissions in establishing a Marginal Area emission offset reduction ratio of 1.1:1 in its NSR program by SIP-approved rule consistent with the corresponding Federal code.

As noted above, section 182(a)(1) requires states to submit a comprehensive, accurate, and current inventory of actual emissions from sources of volatile organic compounds (VOCs) and nitrogen oxides (NO_X) emitted within the boundaries of the ozone nonattainment area. The state's ''Marginal Area Plan for the Missouri Portion of the St. Louis Nonattainment Area for the 2015 8-Hour Ground Level Ozone National Ambient Air Quality Standard'' submitted by the state on September 8, 2021, and supplemented on April 8, 2022, included a 2017 base year emissions inventory for the Missouri portion of the St. Louis area. The EPA has reviewed Missouri's emissions inventory submission and as discussed further below, is proposing to approve it as meeting the requirements of section 182(a)(1) of the CAA.

The section 182(a)(1) base year inventory is defined in the SIP Requirements Rule as ''a comprehensive, accurate, current inventory of actual emissions from sources of VOC and NO_X emitted within the boundaries of the nonattainment area as required by CAA section 182(a)(1).'' *See* 40 CFR 51.1300(p). The inventory year must be selected consistent with the baseline year for the RFP plan as required by 40 CFR 51.1310(b), the inventory must include actual ozone season day emissions as defined in 40 CFR 51.1300(q), and contain data elements consistent with the detail required by 40 CFR part 51, subpart A. *See* 40 CFR 51.1315(a), (c), and (e). In addition, the point source emissions included in the inventory must be reported according to the point source emissions thresholds of the Air Emissions Reporting Requirements (AERR) in 40 CFR part 51, subpart A.

Missouri selected 2017 as the base year for the emissions inventories, which was the most recent calendar year for which a complete triennial inventory was required to be submitted to the EPA under 40 CFR part 51, subpart A, at the time of plan development. This base year is consistent with the regulations for 2015 ozone NAAQS nonattainment area base year emission inventory regulations. *See* 40 CFR 51.1315(a) and 51.1310(b). The emissions inventory is based on data developed and submitted by the MoDNR to EPA's 2017 National Emissions Inventory (NEI), and it contains data elements consistent with the requirements of 40 CFR part 51, subpart A.

Missouri's emissions inventory for the St. Louis Area provides 2017 typical ozone season day emissions for NO_X and VOC for the following general source categories: point sources, nonpoint or area sources, on-road mobile sources, and non-road mobile sources. MoDNR documents the methodology used to determine the typical ozone season day emissions by source category in the appendices to its September 2021 submittal, which is included in the docket for this action.

Point sources are large, stationary, identifiable sources of emissions that release pollutants into the atmosphere. NO_X and VOC emissions were calculated by using facility-specific emissions data reported to the 2017 NEI from sources that are required to submit inventory data according to the AERR. A detailed account of the point source emissions can be found in Appendix D to Missouri's September 2021 submittal and Appendix E to Missouri's April 2022 submittal.

Area or nonpoint sources are small stationary sources of emissions, which due to their large number, collectively have significant emissions (*e.g.,* dry cleaners, service stations). Emissions for these sources are estimated at the county level and were obtained from the 2017 NEI. A detailed account of the area or nonpoint source emissions can be found in Appendix C of Missouri's September 2021 submittal and Appendix E to Missouri's April 2022 submittal.

On-road mobile sources include vehicles used on roads for transportation of passengers or freight. For the St. Louis area, on-road emissions inventories were developed using the latest version of EPA's Motor Vehicle Emissions Simulator (MOVES), MOVES3, for each ozone nonattainment county. County level on-road emissions modeling was conducted using county-specific vehicle populations and other local data. A detailed account of the on-road source emissions and methodology can be found in Appendices A and B of Missouri's September 2021 submittal and Appendix E to Missouri's April 2022 submittal.

Non-road mobile sources include vehicles, engines, and equipment used for construction, agriculture, recreation, and other purposes that do not use the roadways (*e.g.,* lawn mowers, construction equipment, railroad locomotives, and aircraft). Missouri calculated emissions for most non-road sources using the MOVES model's non-road option. Estimated non-road emissions for commercial marine vessels, locomotives and aircraft are based on reported activity data. A detailed account of non-road mobile source emissions can be found in Appendix B of Missouri's September 2021 submittal and Appendix E to Missouri's April 2022 submittal.

As noted in MoDNR's submittal, the 2017 emission inventory is created at the annual level for most source categories. Missouri performed temporal allocation of emissions for all nonpoint, some nonroad and all event source categories using the Sparse Matrix Operator Kernel Emissions (SMOKE) model. For point source data, Missouri utilized reported data to estimate ozone season day emissions specific to each facility. For on-road and non-road emissions, the MOVES3 model provides an output at the temporal scale of total daily emissions. As described in MoDNR's submittal, a typical weekday in July is selected as the representative typical ozone season day for these model runs.

In its April 8, 2022, submittal, MoDNR provided an updated 2017 base year emissions inventory using the latest version of EPA's MOVES3 model for on-road and non-road sources as well as updates to certain non-road categories. Section 7 and Appendix E of Missouri's April 2022 SIP submission included in the docket for this action contain further information related to the updated 2017 nonattainment base year emissions inventory. Table 1 provides a summary of the nonattainment base year anthropogenic emissions inventories for the Missouri portion of the St. Louis area.[3]

[3] This table contains the updated 2017 base year emissions inventory as contained in Table 23 on page 41 of Missouri's April 2022 Submission titled, ''Maintenance Plan for the St. Louis Nonattainment Area for the 2015 Ozone Standard'' which is included in the docket for this action. In April 2022, Missouri separately submitted a redesignation request for the St. Louis area, that submittal also contained information on the updated 2017 base year inventory and is included in the docket for this action, it is titled, ''Redesignation Request for the St. Louis Nonattainment Area for the 2015 Ozone Standard.''

TABLE 1—2017 EMISSIONS FOR THE MISSOURI PORTION OF THE ST. LOUIS AREA

[Tons/ozone season day]

County	Point		Area		On-road		Non-road	
	NO_X	VOC	NO_X	VOC	NO_X	VOC	NO_X	VOC
Boles Township, Franklin County	21.86	1.29	0.08	1.08	1.40	0.49	0.64	0.25
Jefferson County	22.37	2.24	0.48	6.99	8.88	3.42	2.47	1.66
St. Charles County	18.94	3.71	0.92	12.03	11.36	3.94	5.63	3.79
St. Louis County	5.54	1.30	2.83	39.08	37.30	10.53	14.21	16.37
St. Louis City	3.19	2.71	0.99	10.46	9.97	3.68	3.78	1.86
Total	71.90	11.25	5.29	69.65	68.92	22.05	26.74	23.94

Missouri's April 2022 submittal contains additional plan elements such as maintenance plan, contingency plan and attainment year inventory. In today's action, the EPA is only proposing to approve the updated 2017 nonattainment base year emissions inventory as included in the April 2022 submittal as meeting the requirements of CAA section 182(a)(1) and is not acting on the other elements contained in the April 2022 submittal. The EPA has reviewed Missouri's nonattainment base year emissions inventories for the St. Louis Area and proposes to approve them as meeting the requirements under CAA section 182(a)(1) and the SIP Requirements Rule for the 2015 8-hour ozone NAAQS, as well as the requirements in 40 CFR part 51, subpart A. Specifically, EPA proposes to approve Missouri's Marginal nonattainment area plan as submitted on September 8, 2021 and supplemented on April 8, 2022, as meeting the Marginal nonattainment area requirements of CAA section 182(a) for the 2015 8-hour ozone NAAQS for the Missouri portion of the St. Louis area.

IV. Have the requirements for approval of a SIP revision been met?

The State submission has met the public notice requirements for SIP submissions in accordance with 40 CFR 51.102. The submission also satisfied the completeness criteria of 40 CFR part 51, appendix V. The State provided public notice on the September 8, 2021, SIP revision from April 26, 2021, to June 3, 2021, and held a public hearing on May 27, 2021. During the public comment period, the State received three comments from the EPA. The State responds to the comments in its submittal and made changes to the plan as a result of the comments. The State provided public notice on the April 8, 2022, SIP revision from December 27, 2021, to February 3, 2022, and held a public hearing on January 27, 2022. During the public comment period, the State received comments from various entities. The State addressed the comments in its submittal. No comments received on the April 8, 2022, submittal were related to the updated 2017 nonattainment base year emissions inventory. In addition, as explained above, the revision meets the substantive SIP requirements of the CAA and implementing regulations.

V. What action is the EPA proposing to take?

The EPA is proposing to approve a SIP revision submitted by the MoDNR on September 8, 2021, and supplemented on April 8, 2022, as meeting the Marginal nonattainment area requirements of CAA section 182(a) for the 2015 8-hour ozone NAAQS for the Missouri portion of the St. Louis area.

VI. Environmental Justice Considerations

While EPA did not perform an area-specific environmental justice analysis for purposes of this action, due to the nature of the action being taken here, *i.e.* to merely approve emissions inventories and certifications regarding Missouri's fully approved permitting program as meeting the relevant plan requirements for Marginal nonattainment areas, as explained in this preamble, this action is expected to have no impact on air quality. For these reasons, this action is not expected to have a disproportionately high or adverse human health or environmental effects on a particular group of people.

VII. Statutory and Executive Order Reviews

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

- Is not a significant regulatory action subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of the National Technology Transfer and Advancement Act (NTTA) because this rulemaking does not involve technical standards; and
- This action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994). The basis for this determination is contained in section VI of this action, ''Environmental Justice Considerations.''

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction. In those areas of Indian country, this rule does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because redesignation is an action that affects the status of a geographical area and does not impose any new regulatory requirements on tribes, impact any existing sources of air pollution on tribal lands, nor impair the maintenance of ozone national ambient air quality standards in tribal lands.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Oxides of nitrogen, Ozone, Volatile organic compounds.

Dated: November 30, 2022.

Meghan A. McCollister,

Regional Administrator, Region 7.

For the reasons stated in the preamble, the EPA proposes to amend 40 CFR part 52 as set forth below:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

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

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

Subpart AA—Missouri

■ 2. In § 52.1320, the table in paragraph (e) is amended by adding the entry ''(85)'' to read as follows:

§ 52.1320 Identification of plan.

* * * * *

(e) * * *

EPA-APPROVED MISSOURI NONREGULATORY SIP PROVISIONS

Name of nonregulatory SIP provision	Applicable geographic or nonattainment area	State submittal date	EPA approval date	Explanation
*	*	*	*	*
(85) Marginal Plan for the St. Louis 2015 8-Hour Ozone Non-attainment Area.	St. Louis Area: Missouri counties of Jefferson, St. Charles, and St. Louis along with the City of St. Louis and Boles Township in Franklin County.	9/8/2021, 4/8/2022.	[Date of publication of the final rule in the **Federal Register**], [**Federal Register** citation of the final rule].	This action approves the Marginal nonattainment area plan for the St. Louis Area for the 2015 8-hour Ozone NAAQS [EPA–R07–OAR–2022–0880; FRL–10388–01–R7].

* * * * *

[FR Doc. 2022–26503 Filed 12–5–22; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52 and 81

[EPA–R08–OAR–2021–0003; FRL–10454–01–R8]

Approval and Promulgation of Implementation Plans; Montana; Libby 1997 Annual $PM_{2.5}$ Limited Maintenance Plan and Redesignation Request

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA or the Agency) is proposing to take three separate but related actions. First, EPA is proposing to determine that the Libby fine particulate matter ($PM_{2.5}$) nonattainment area (Libby Area) is attaining the 1997 annual $PM_{2.5}$ national ambient air quality standards (NAAQS or standard) based on 2014–2021 data. The Agency is also proposing to approve Montana's plan for maintaining the 1997 annual $PM_{2.5}$ NAAQS (limited maintenance plan) and to redesignate the Libby Area to attainment for the 1997 annual $PM_{2.5}$ NAAQS, submitted by the State of Montana on June 24, 2020.

DATES: Written comments must be received on or before January 5, 2023.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R08–OAR–2021–0003, to the Federal Rulemaking Portal at *https://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *www.regulations.gov.* EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

Docket: All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available electronically in *www.regulations.gov.* To reduce the risk of COVID–19 transmission, for this action we do not plan to offer hard copy review of the docket. Please email or call the person listed in the **FOR FURTHER INFORMATION CONTACT** section if you need to make alternative arrangements for access to the docket.

FOR FURTHER INFORMATION CONTACT: Amrita Singh, Air and Radiation Division, U.S. Environmental Protection Agency (EPA), Region 8, Mail Code ARD–QP, 1595 Wynkoop Street, Denver, Colorado 80202–1129, telephone number: (303) 312–6103, email address: *singh.amrita@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document wherever ''we,'' ''us,'' or ''our'' is used, we mean EPA.

Table of Contents

I. What are the actions EPA is proposing to take?

EPA is proposing to take the following separate but related actions: (1) to determine that the Libby Area is attaining the 1997 annual $PM_{2.5}$ NAAQS based on 2014–2021 data; (2) to approve Montana's plan for maintaining the 1997 annual $PM_{2.5}$ NAAQS (limited maintenance plan); and (3) to redesignate the Libby Area to attainment for the 1997 annual $PM_{2.5}$ NAAQS.

Libby, Montana is a small rural community located in Lincoln County in the northwestern part of the State. Libby sits in the narrow, triangular Kootenai valley at an elevation of 2,100 feet. The Libby Area is dominated by three major mountain ranges that limit the air-shed: (1) the Rocky Mountain and Flathead Ranges on the eastern boundary; (2) the Purcell Range, which roughly bisects the area from north to south; and (3) the Selkirk and Cabinet Ranges on the western boundary. Most of the area surrounding Libby, Montana is national forest land managed by the U.S. Forest Service.

These proposed actions are summarized and described in greater detail throughout this proposed rulemaking. EPA's 1997 annual $PM_{2.5}$ nonattainment designation for the Libby Area triggered an obligation for Montana to develop a nonattainment state implementation plan (SIP) revision addressing certain Clean Air Act (CAA) requirements under title I, part D, subpart 1 (hereinafter ''Subpart 1'') and title I, part D, subpart 4 (hereinafter ''Subpart 4''). Subpart 1 contains the general requirements for nonattainment areas for criteria pollutants, including requirements to develop a SIP that provides for the implementation of reasonably available control measures (RACM) under section 172(c)(1), reasonable further progress (RFP), includes base-year and attainment-year emissions inventories, and for the implementation of contingency measures. As discussed in greater detail later in this document, Subpart 4 contains specific planning and scheduling requirements for coarse particulate matter (PM_{10}) nonattainment areas, including requirements for new source review (NSR), RACM (under CAA section 189(a)(1)(C)), and RFP. EPA's longstanding general guidance interpreting the 1990 CAA Amendments, known as the General Preamble, EPA discussed the relationship of Subpart 1 and Subpart 4 SIP requirements and pointed out that Subpart 1 requirements were to an extent ''subsumed by, or integrally related to, the more specific PM–10 requirements.'' See 57 FR 13538 (April 16, 1992). In addition, under the United States Court of Appeals for the District of Columbia Circuit's (D.C. Circuit's) January 4, 2013, decision in *Natural Resources Defense Council (NRDC)* v. *EPA,* 706 F.3d 428 (D.C. Cir. 2013), Subpart 4 requirements apply to $PM_{2.5}$ nonattainment areas.[1]

On June 2, 2014 (79 FR 31566), EPA published a rule entitled ''Identification of Nonattainment Classification and Deadlines for Submission of State Implementation Plan (SIP) Provisions for the 1997 Fine Particle ($PM_{2.5}$) National Ambient Air Quality Standard (NAAQS) and 2006 $PM_{2.5}$ NAAQS'' (''Classification and Deadlines Rule''). In that rule, the Agency responded to the D.C. Circuit's January 2013 decision by identifying all $PM_{2.5}$ nonattainment areas for the 1997 and 2006 $PM_{2.5}$ NAAQS as ''Moderate'' nonattainment areas under Subpart 4, and by establishing a new SIP submission date of December 31, 2014, for Moderate area attainment plans and for any additional attainment-related or nonattainment new source review plans necessary for areas to comply with the requirements applicable under Subpart 4. Id. at 31567–70.

EPA is proposing to determine that the Libby Area is attaining the 1997 annual $PM_{2.5}$ NAAQS based on recent air quality data. EPA is also proposing to approve Montana's limited maintenance plan (LMP) for the Libby Area as meeting the requirements of section 175A of the CAA.

EPA also proposes to determine that the Libby Area has met the requirements for redesignation under section 107(d)(3)(E) of the CAA. This proposed rulemaking is in response to Montana's June 24, 2020 redesignation request and associated SIP submission that address the requirements described in section 107(d)(3)(E) of the CAA for the redesignation of the Libby Area from nonattainment to attainment for the 1997 annual $PM_{2.5}$ NAAQS.[2]

II. What is the background for EPA's proposed actions?

A. The $PM_{2.5}$ NAAQS

Particulate matter includes particles with diameters that are generally 2.5 microns or smaller ($PM_{2.5}$) and particles with diameters that are generally 10 microns or smaller (PM_{10}). $PM_{2.5}$ contributes to effects that are harmful to human health and the environment, including premature mortality, aggravation of respiratory and cardiovascular disease, decreased lung function, visibility impairment, and damage to vegetation and ecosystems. Individuals particularly sensitive to $PM_{2.5}$ exposure include older adults, people with heart and lung disease, and children. See 78 FR 3086 at 3088 (January 15, 2013). $PM_{2.5}$ can be emitted directly into the atmosphere as a solid or liquid particle (''primary $PM_{2.5}$'' or ''direct $PM_{2.5}$'') or can be formed in the atmosphere (''secondary $PM_{2.5}$'') as a result of various chemical reactions among precursor pollutants such as nitrogen oxides (NO_X), sulfur oxides (SO_X), volatile organic compounds (VOCs), and ammonia (NH_3).[3]

Under section 109 of the CAA, EPA has established national ambient air quality standards for certain pervasive air pollutants (referred to as ''criteria pollutants'') and conducts periodic reviews of the NAAQS to determine whether they should be revised or whether new NAAQS should be established. EPA sets the NAAQS for criteria pollutants at levels required to protect public health and welfare.[4]

[1] In explaining its decision, the Court reasoned that the plain meaning of the CAA requires implementation of the 1997 $PM_{2.5}$ NAAQS under Subpart 4 because $PM_{2.5}$ particles fall within the statutory definition of PM_{10} and are thus subject to the same statutory requirements. EPA finalized its interpretation of Subpart 4 requirements as applied to the $PM_{2.5}$ NAAQS in its final rule entitled ''Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements; Final Rule'' (81 FR 58010, August 24, 2016).

[2] *See* Libby Area SIP submission, available in the docket for this proposed rulemaking.

[3] EPA, Air Quality Criteria for Particulate Matter, No. EPA/600/P–99/002aF and EPA/600/P–99/002bF, October 2004.

[4] For a given air pollutant, ''primary'' national ambient air quality standards are those determined by EPA as requisite to protect the public health. ''Secondary'' standards are those determined by EPA as requisite to protect the public welfare from

$PM_{2.5}$ is one of the ambient pollutants for which EPA has established health-based standards.

On July 18, 1997 (62 FR 38652), EPA revised the NAAQS for particulate matter to add new standards for $PM_{2.5}$. The Agency established primary and secondary annual and 24-hour standards for $PM_{2.5}$. The annual standard was set at 15.0 micrograms per meter cubed (μg/m³) based on a 3-year average of annual mean $PM_{2.5}$ concentrations, and the 24-hour (daily) standard was set at 65 μg/m³ based on the 3-year average of the annual 98th percentile values of 24-hour $PM_{2.5}$ concentrations at each population-oriented monitor within an area.[5]

On October 17, 2006 (71 FR 61144), EPA retained the annual average NAAQS at 15.0 μg/m³ but revised the level of the 24-hour $PM_{2.5}$ NAAQS to 35 μg/m³ based on a 3-year average of the annual 98th percentile values of 24-hour concentrations.[6]

On December 14, 2012, EPA promulgated the 2012 $PM_{2.5}$ NAAQS, including a revision of the annual standard to 12.0 μg/m³ based on a 3-year average of annual mean $PM_{2.5}$ concentrations. The Agency maintained the 24-hour standard of 35 μg/m³ based on a 3-year average of the 98th percentile of 24-hour concentrations. See 78 FR 3086 (January 15, 2013).

B. Designation of $PM_{2.5}$ NAAQS Nonattainment Areas

Following promulgation of a new or revised NAAQS, EPA is required by CAA section 107(d) to designate areas throughout the nation as attaining or not attaining the NAAQS. On January 5, 2005 (70 FR 944), EPA published area designations for the 1997 $PM_{2.5}$ NAAQS based on air quality data for the calendar years 2001–2003. In that rulemaking, EPA designated Libby, Montana as nonattainment for the 1997 annual $PM_{2.5}$ NAAQS. These designations became effective on April 5, 2005.

On March 17, 2011 (76 FR 14584), EPA approved Montana's attainment plan which included an attainment demonstration, an analysis of reasonable available control technology/reasonable available control measure (RACT/RACM), base-year and projection year inventories, and contingency measures for the 1997 $PM_{2.5}$ NAAQS for the Libby Area. On July 14, 2015 (80 FR 40911), EPA finalized its determination that the Libby Area attained the 1997 annual $PM_{2.5}$ NAAQS by the Area's statutory attainment date of December 31, 2011. This determination was based upon quality-assured and certified ambient air monitoring data for the 2007–2009 monitoring period that demonstrated that the Libby Area attained the 1997 annual $PM_{2.5}$ NAAQS by the attainment date. In the same rulemaking, EPA also issued a clean data determination under the Agency's Clean Data Policy[7] based upon quality-assured and certified ambient air monitoring data that demonstrated the Libby Area continued to attain the 1997 annual $PM_{2.5}$ NAAQS based on 2012–2014 monitoring data.[8]

On July 29, 2016, EPA issued a rule entitled ''Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements'' (''$PM_{2.5}$ SIP Requirements Rule''). See 81 FR 58010 (August 24, 2016). This rule clarifies how states should meet the statutory SIP requirements that apply to areas designated nonattainment for any $PM_{2.5}$ NAAQS under Subparts 1 and 4. It does so by establishing regulatory requirements and by providing guidance that is applicable to areas that are currently designated nonattainment for existing $PM_{2.5}$ NAAQS and areas that are designated nonattainment for any $PM_{2.5}$ NAAQS in the future. In addition, the rule responds to the D.C. Circuit's remand of the 1997 $PM_{2.5}$ Implementation Rules. As a result, the requirements of the rule also govern future actions associated with states' ongoing implementation efforts for the 1997 and 2006 $PM_{2.5}$ NAAQS. In the $PM_{2.5}$ SIP Requirements Rule, EPA revoked the 1997 primary annual $PM_{2.5}$ NAAQS in areas that had always been attainment for that NAAQS, and in areas that had been designated as nonattainment but that were redesignated to attainment before October 24, 2016, the $PM_{2.5}$ SIP Requirements Rule effective date. See 81 FR 58010 (August 24, 2016).

In the August 24, 2016 final rule, EPA also finalized a provision to revoke the 1997 primary annual $PM_{2.5}$ NAAQS in areas redesignated to attainment after October 24, 2016, on the effective date of an area's redesignation. See 40 CFR 50.13(d). If this proposal is finalized, the 1997 primary annual $PM_{2.5}$ NAAQS will be revoked for the Libby Area on the effective date of the redesignation. Beginning on that date, the Area will no longer be subject to transportation or general conformity requirements for the 1997 annual $PM_{2.5}$ NAAQS due to revocation of the primary NAAQS. See 81 FR 58125–6. If redesignated, the Libby Area will be required to implement the maintenance plan requirements under section 175A for the 1997 annual $PM_{2.5}$ NAAQS, and the prevention of significant deterioration (PSD) program for the 1997 annual $PM_{2.5}$ NAAQS. Once approved, the maintenance plan can only be revised if the revision meets the requirements of CAA section 110(l) and, if applicable, CAA section 193. As described in the $PM_{2.5}$ SIP Requirements Rule, those 1997 annual $PM_{2.5}$ maintenance areas with a revoked NAAQS are no longer required to submit a second 10-year maintenance plan for the 1997 annual $PM_{2.5}$ NAAQS. See 81 FR 58144.

C. $PM_{2.5}$ NAAQS Nonattainment Area Planning Requirements

The CAA establishes the requirements for redesignation of an area from nonattainment to attainment. Specifically, section 107(d)(3)(E) allows for redesignation of areas from nonattainment to attainment provided that the following criteria are met:

(1) The Administrator has determined that the area has attained the applicable NAAQS;

(2) The Administrator has fully approved the applicable SIP for the area under section 110(k) of the CAA;

(3) The Administrator has determined that the improvement in air quality is due to permanent and enforceable reductions in emissions;

(4) The Administrator has fully approved a maintenance plan for the area as meeting the requirements of section 175A of the CAA; and

(5) The state containing the area has met all requirements applicable to the area under section 110 and part D of the CAA.

Section 110 of the CAA identifies a comprehensive list of elements that SIPs must include, and part D establishes the SIP requirements for nonattainment areas. The generally applicable nonattainment SIP requirements are found in part D, subpart 1, and the particulate matter-specific SIP

any known or anticipated adverse effects associated with the presence of such air pollutant in the ambient air. CAA section 109(b).

[5] The primary and secondary standards were set at the same level for both the 24-hour and the annual $PM_{2.5}$ standards.

[6] Under EPA regulations at 40 CFR part 50, the primary and secondary 2006 24-hour $PM_{2.5}$ NAAQS are attained when the annual arithmetic mean concentration, as determined in accordance with 40 CFR part 50, appendix N, is less than or equal to 35 μg/m³ at all relevant monitoring sites in the subject area, averaged over a 3-year period.

[7] *See e.g.,* 70 FR 71612 (November 29, 2005) and 72 FR 20586 (April 25, 2007).

[8] *See* 71 FR 19935 (April 14, 2015) that addresses the final clean data determination and a final determination of attainment by the attainment date for the Libby nonattainment area. As part of its clean data determination submission to EPA, Montana submitted the clean data determination to address the national ambient air requirements under Subpart 4.

requirements are found in part D, subpart 4.

On April 16, 1992 (57 FR 13498), EPA provided guidance on redesignation in the General Preamble for the Implementation of Title I of the CAA Amendments of 1990, and the Agency supplemented this guidance on April 28, 1992 (57 FR 18070). EPA has provided further guidance on processing redesignation requests in the following documents:

1. ''Procedures for Processing Requests to Redesignate Areas to Attainment,'' Memorandum from John Calcagni, Director, Air Quality Management Division, September 4, 1992 (hereinafter referred to as the ''Calcagni Memorandum'');

2. ''State Implementation Plan (SIP) Actions Submitted in Response to Clean Air Act (CAA) Deadlines,'' Memorandum from John Calcagni, Director, Air Quality Management Division, October 28, 1992; and

3. ''Part D New Source Review (Part D NSR) Requirements for Areas Requesting Redesignation to Attainment,'' Memorandum from Mary D. Nichols, Assistant Administrator for Air and Radiation, October 14, 1994 (hereinafter referred to as the ''Nichols Memorandum'').

D. Limited Maintenance Plans

CAA section 175A(a) requires that nonattainment areas seeking redesignation to attainment submit ''a revision of the applicable state implementation plan to provide for the maintenance of the [NAAQS] for such air pollutant in the area concerned for at least 10 years after the redesignation.'' EPA explained in the Calcagni Memorandum that states may meet this requirement to ''provide for the maintenance of the NAAQS'' by using projected emissions inventories or air quality modeling showing continued maintenance until the end of the relevant maintenance period. See Calcagni Memorandum at 9–11. EPA clarified in three subsequent guidance memos that certain areas could meet the CAA section 175A requirement to provide for maintenance by demonstrating that the area's design value was well below the NAAQS and that the historical stability of the area's air quality levels showed that the area was unlikely to violate the NAAQS in the future.[9] The Agency refers to this streamlined demonstration of maintenance as a limited maintenance plan.

EPA has interpreted CAA section 175A as permitting this option because section 175A does not define how areas may demonstrate maintenance, and in EPA's experience with implementing the various NAAQS, areas that qualify for an LMP and have approved LMPs, have rarely, if ever, experienced subsequent violations of the NAAQS. As noted in the LMP guidance memoranda, states seeking an LMP must still submit the other maintenance plan elements outlined in the Calcagni Memorandum, including an attainment emissions inventory, provisions for the continued operation of the ambient air quality monitoring network, verification of continued attainment, and a contingency plan in the event of a future violation of the NAAQS. Moreover, states seeking to do an LMP must still submit a CAA section 175A maintenance plan as a revision to the SIP, with all attendant notice and comment procedures. While the LMP guidance memoranda were originally written with respect to certain NAAQS,[10] EPA has extended the LMP interpretation of section 175A to other NAAQS and pollutants not specifically covered by the previous guidance memos.[11]

To determine the LMP eligibility criteria for the Libby Area, EPA is interpreting the requirements as described in the 2001 memorandum from Lydia Wegman[12] regarding LMPs for PM_{10} areas as applying to $PM_{2.5}$. This memorandum states that one way for a PM_{10} area to qualify for an LMP is to show that the area's average design value (ADV) (based upon the most recent 5 years of monitoring data) is at or below the critical design value (CDV). The memorandum defines the CDV as an indicator of the likelihood of future violations of the NAAQS in an area given the area's current ADV and its historical variability and provides a means for calculating the CDV for an area (or monitoring site) (Attachment A of the 2001 Wegman Memorandum). The CDV is the highest average design value an area could have before it may experience a future violation of the NAAQS with a certain probability—in the case of the Wegman Memorandum, a probability of 1 in 10. Therefore, if an area's current ADV is less than the area's CDV, that area has a less than 1 in 10 chances of violating the NAAQS in the future. As noted in Attachment A of the Wegman Memorandum, the CDV calculation was designed to apply for any NAAQS pollutant and is not specific to PM_{10}. Montana employed this methodology to demonstrate that the Libby Area is eligible for an LMP and that the plan therefore provides for maintenance of the NAAQS for 10 years following redesignation. We agree that the State's demonstration meets the requirements of CAA section 175A and shows that the Area will continue to maintain the annual $PM_{2.5}$ NAAQS following redesignation through 2031. In its SIP submission, Montana used a site-specific CDV calculated with $PM_{2.5}$ data from the one ambient design value monitor in the Libby Area.

The 2001 Wegman Memorandum also provided that an LMP was appropriate only for those PM_{10} areas that were expecting limited growth of on-road motor vehicle emissions (including fugitive dust), and therefore included a motor vehicle regional emissions analysis demonstration that states seeking a PM_{10} LMP should perform (Attachment B to the Wegman Memorandum). According to the Wegman Memorandum, the demonstration should show that the ADV remains below the margin of safety provided for in the memorandum, even after the growth of on-road motor vehicle emissions is considered. This proposed rulemaking uses the site-specific CDV instead of the margin of safety described in the Wegman Memorandum for this analysis as EPA has not recommended a margin of safety for the 1997 annual $PM_{2.5}$ NAAQS.

III. Why is EPA proposing these actions?

On June 24, 2020, the State of Montana requested that EPA redesignate the Libby Area to attainment for the 1997 annual $PM_{2.5}$ NAAQS and submitted an associated SIP revision containing an LMP. EPA's evaluation of the plan and air quality data indicates that the Libby Area meets the requirements for redesignation set forth in section 107(d)(3)(E) of the CAA, including that the LMP fulfills the maintenance plan requirements under section 175A of the CAA. As a result of these findings, EPA is proposing to take the separate but related actions to approve the LMP and redesignate the

[9] See ''Limited Maintenance Plan Option for Nonclassifiable Ozone Nonattainment Areas'' from Sally L. Shaver, Office of Air Quality Planning and Standards (OAQPS), dated November 16, 1994; ''Limited Maintenance Plan Option for Nonclassifiable CO Nonattainment Areas'' from Joseph Paisie, OAQPS, dated October 6, 1995; Copies of these guidance memoranda can be found in the docket for this proposed rulemaking.

[10] The prior memos addressed unclassifiable areas under the 1-hour ozone NAAQS, nonattainment areas for the PM_{10} NAAQS, and nonattainment areas for the carbon monoxide NAAQS.

[11] *See, e.g.,* 79 FR 41900 (July 18, 2014) (approval of second ten-year LMP for Grant County 1971 sulfur dioxide maintenance area).

[12] ''Limited Maintenance Plan Option for Moderate PM_{10} Nonattainment Areas'' from Lydia Wegman, OAQPS, dated August 9, 2001 (hereinafter referred to as the ''Wegman Memorandum''). A copy of this guidance memorandum can be found in the docket for this proposed rulemaking.

Libby Area from nonattainment to attainment.

IV. What is EPA's analysis of the request?

To redesignate an area from nonattainment to attainment, the CAA requires EPA to determine that the area has attained the applicable NAAQS (CAA section 107(d)(3)(E)(i)). The criteria for determining if an area is attaining the 1997 annual $PM_{2.5}$ NAAQS is set out in 40 CFR 50.13 and 40 CFR part 50, appendix N. The 1997 annual $PM_{2.5}$ primary and secondary standards are met when the annual design value [13] at each eligible monitoring site within the area is less than or equal to 15.0 µg/m³.

Based on data from 2007–2009, EPA determined that the Libby Area attained the 1997 annual $PM_{2.5}$ standard by December 31, 2011, well before its attainment date of July 14, 2015.[14] In addition, EPA issued a final clean data determination under the Clean Data Policy that the Libby Area was attaining the 1997 annual $PM_{2.5}$ NAAQS, based on quality-assured and certified ambient air quality data for the 2012–2014 monitoring period. The Libby Area has continued to attain the 1997 annual $PM_{2.5}$ NAAQS since EPA's earlier determinations that the Area attained the NAAQS.

The Libby Area has one State and Local Air Monitoring Station (SLAMS) monitor operated by the Montana Department of Environmental Quality (MDEQ). This monitor (Air Quality System (AQS) Site ID 30–53–0018) has complete data for 2014–2021, which is the period of data utilized for this proposed redesignation.[15]

Table 1 summarizes the annual mean $PM_{2.5}$ data collected from 2014–2021 for the Libby Area.[16] Table 2 shows the annual design values for 2016–2021. The data presented in the tables were calculated from all data available in AQS, including those data flagged by the State of Montana as potentially influenced by exceptional events. EPA deems these data valid as they are complete and have been certified by MDEQ.

None of the annual design values from 2016–2021 from the Libby Area monitoring site exceed the 1997 annual $PM_{2.5}$ NAAQS of 15.0 µg/m³, and as such, EPA proposes to determine that the Libby Area has attained the 1997 annual $PM_{2.5}$ NAAQS, and therefore meets the requirement of CAA section 107(d)(3)(E)(i).

TABLE 1—$PM_{2.5}$ ONE-YEAR ANNUAL MEAN CONCENTRATIONS [17]

Year:	2014	2015	2016	2017	2018	2019	2020	2021
Concentration (µg/m³)	9.3	14.9	9.8	14.3	14.6	11.4	13.8	14.6

TABLE 2—$PM_{2.5}$ ANNUAL DESIGN VALUE [18]

3-Year Period:	2014–2016	2015–2017	2016–2018	2017–2019	2018–2020	2019–2021
Design Value (µg/m³)	11.4	13.0	12.9	13.4	13.3	13.3

A. Has the State met all applicable requirements under section 110 and part D of the Clean Air Act (CAA) and have those requirements been fully approved? (CAA sections 107(d)(3)(E)(ii) and (v))

Sections 107 (d)(3)(E)(ii) and (v) require EPA to determine that the area has a fully approved applicable SIP under section 110(k) that meets all the basic applicable requirements under section 110 and part D for purposes for redesignation. The following is a summary of how Montana meets these requirements.

1. CAA Section 110 Requirements

Section 110(a)(2) of title I of the CAA delineates the general requirements for a SIP, which include enforceable emissions limitations and other control measures, means or techniques, provisions for the establishment and operation of appropriate devices necessary to collect data on ambient air quality, and programs to enforce limitations. The general SIP elements and requirements set forth in CAA section 110(a)(2) include, but are not limited to the following:

- Submittal of a SIP that has been adopted by the state after reasonable public notice and hearing;
- Provisions for establishment and operation of appropriate procedures needed to monitor ambient air quality;
- Implementation of a source permit program;
- Provisions for the implementation of part C requirements (PSD);
- Provisions for the implementation of part D requirements for NSR permit programs;
- Provisions for air pollution modeling; and
- Provisions for public and local air agency participation in planning and emission control rule development.

CAA section 110(a)(2)(D) requires that SIPs contain certain measures to prevent sources in a state from significantly contributing to air quality problems in another state; the portion of a state's SIP that include these measures is known as an interstate transport SIP. However, these CAA section 110(a)(2)(D) requirements apply to a state and are not linked with a particular nonattainment area's designation and classification in that state. The interstate transport SIP submittal requirements, where applicable, continue to apply to a state regardless of the designation of any one area in the state. Thus, EPA has determined that these requirements are not applicable requirements for purposes of redesignation. Instead, EPA has determined that the requirements

[13] The Annual $PM_{2.5}$ NAAQS design value is the 3-year average of $PM_{2.5}$ annual mean mass concentrations. These annual means are calculated as the weighted arithmetic mean of the four quarters of valid data at the site and the annual means are only considered valid when they meet data completeness requirements detailed in 40 CFR 50.13. Once three valid annual means are available, they can be averaged together to determine the annual design value for that site.

[14] See 80 FR 40911.

[15] The criteria for determining if an area is attaining the 1997 Annual $PM_{2.5}$ NAAQS are set out in the 40 CFR 50.13 and 40 CFR part 50, appendix N. Three years of valid annual means are required to produce a valid annual standard design value. A year meets data completeness requirements when at least 75 percent of the scheduled sampling days for each quarter have valid data.

[16] The annual averages in Table 1 are calculated by averaging the four quarters of data.

[17] Annual mean concentration is the averaging of four complete quarters of data for each year. See 40 CFR part 50, appendix N.

[18] The Annual $PM_{2.5}$ NAAQS design value is the 3-year average of $PM_{2.5}$ annual mean mass concentrations. See 40 CFR 50.13.

linked with a particular nonattainment area's designation and classifications are the relevant measures, *i.e.,* the requirements that must be met, for EPA to redesignate an area.

In addition, EPA has determined that the other CAA section 110(a)(2) elements not connected with nonattainment plan submissions and not linked with an area's attainment status are not applicable requirements for purposes of redesignation because the area will still be subject to these requirements after it is redesignated. EPA concludes that the CAA section 110(a)(2) and part D requirements, which are linked with a particular area's designation and classification, are the relevant measures to evaluate in reviewing a redesignation request, and that section 110(a)(2) elements not linked to the area's nonattainment status are not applicable for purposes of redesignation. EPA has applied this interpretation consistently in many redesignations.[19]

EPA's review of the Montana SIP shows that the State has satisfied the general SIP requirements under section 110(a)(2) of the CAA, to the extent they are applicable for the purposes of redesignation. Moreover, EPA has previously approved provisions of Montana's SIP as demonstrating compliance with the CAA section 110(a)(2) requirements for the 1997 annual $PM_{2.5}$ NAAQS. See 78 FR 45864 (July 30, 2013). Therefore, EPA proposes to determine that MDEQ has met all general SIP requirements for the Libby Area that are applicable for purposes of redesignation under section 110 of the CAA.

2. Part D Requirements

Subparts 1 and 4 of part D, title 1 of the CAA contain air quality planning requirements for $PM_{2.5}$ nonattainment areas. Subpart 1 contains general requirements for all nonattainment areas of any pollutant, including $PM_{2.5}$, governed by a NAAQS. Subpart 1 requirements include, among other things, provisions for RACM, RFP, emissions inventories, contingency measures, transportation conformity and general conformity. Subpart 4 contains specific planning and scheduling requirements for $PM_{2.5}$ nonattainment areas. Sections 189(a), (c), (e) requirements apply specifically to Moderate $PM_{2.5}$ nonattainment areas and include an approved permit program for construction of new and modified major stationary sources, provisions for RACM, an attainment demonstration, quantitative milestones demonstrating RFP toward attainment by the applicable attainment date, and provisions to ensure that the control requirements applicable to major stationary sources of $PM_{2.5}$ precursors, except where the Administrator has determined that such sources do not contribute significantly to $PM_{2.5}$ levels that exceed the NAAQS in the area.

We address the applicability of these requirements to this action in the following sections.

3. Subpart 1, Section 172 Requirements

Section 172(c) contains general requirements for nonattainment area plan provisions. A thorough discussion of these requirements may be found in the General Preamble. *See* 57 FR 13538 (April 16, 1992). EPA's longstanding interpretation is that certain planning requirements designed to get a nonattainment area to attainment of the NAAQS are not ''applicable'' for purposes of CAA section 107(d)(3)(E)(ii) and (v) and therefore need not be approved into the SIP before EPA can redesignate the area. In the General Preamble, EPA set forth its interpretation of applicable requirements for purposes of evaluating redesignation requests when an area is attaining the standard. *See* 57 FR 13564. EPA noted that requirements for RFP and other measures designed to provide for an area's attainment do not apply in evaluating redesignation because those nonattainment planning requirements ''have no meaning'' for an area that is attaining the standard. *Id.* This interpretation is also set forth in the Calcagni Memorandum.

EPA's understanding of CAA section 172 also forms its basis on its Clean Data Policy. Under the Clean Data Policy, EPA promulgates a determination of attainment, published in the **Federal Register**, which is subject to notice-and-comment rulemaking, and this determination formally suspends a state's obligation to submit most of the attainment planning requirements that would otherwise apply, including an attainment demonstration and planning SIPs to provide for RFP, RACM, and contingency measures under CAA section 179(c)(9). The Clean Data Policy has been codified in regulations regarding the implementation of the ozone and $PM_{2.5}$ NAAQS. *See e.g.,* 70 FR 71612 (November 29, 2005) and 72 FR 20586 (April 25, 2007).

Because the Libby Area is attaining the 1997 annual $PM_{2.5}$ NAAQS, the attainment planning obligations in CAA section 172, including the requirement to submit an attainment demonstration and RACM (172(c)(1)), RFP (172(c)(2)), and contingency measures (172(c)(9)) are not considered ''applicable'' requirements for redesignation purposes under CAA section 107(d)(3)(E)(ii) and (v). In any case, Montana submitted these elements as part of the Moderate SIP requirements on March 26, 2008, and EPA approved them on March 17, 2011.[20]

Section 172(c)(3) of the CAA requires a comprehensive, accurate, current inventory of actual emissions from all sources of relevant pollutant(s) in nonattainment areas. EPA's March 17, 2011 approval of Montana's March 26, 2008 SIP submission included a 2005 base-year emissions inventory for the Libby Area. Montana also included an emissions inventory for calendar year 2014 with the June 24, 2020 SIP submittal of the LMP for the Libby Area. The 2001 Wegman Memorandum states that an attainment inventory should represent emissions during the same 5-year period associated with the air quality data used to determine that the area meets the requirements of the LMP option. In addition, EPA reviewed an updated 2017 emissions inventory[21] in its analysis for the Libby $PM_{2.5}$ LMP.

Section 172(c)(4) requires the identification and quantification of allowable emissions for major new and modified stationary sources in an area, and section 172(c)(5) and 189(a)(1)(A) requires source permits for the construction and operation of new and modified major stationary sources anywhere in the nonattainment area. EPA approved the current Montana NSR program for $PM_{2.5}$ on July 18, 1995. See 60 FR 36715. Having a fully approved nonattainment NSR program is not an applicable requirement for this action; nonetheless we have approved the State's program.[22]

Section 172(c)(7) requires the SIP meet the applicable provisions of CAA

[19] *See, e.g.,* 81 FR 4420 (July 17, 2006) (final redesignation for the Sullivan County, Tennessee area); 79 FR 43655 (July 28, 2014) (final redesignation for Bellefontaine, Ohio lead nonattainment area); 61 FR 53174–53176 (October 10, 1996) and 62 FR 24826 (May 7 1997) (proposed and final redesignation of Reading, Pennsylvania ozone nonattainment area); 61 FR 20458 (May 7 1996) (final redesignation for Cleveland-Akron-Lorain, Ohio ozone nonattainment area); 60 FR 62748 (December 7, 1995) (final redesignation of Tampa, Florida ozone nonattainment area); *See* also 65 FR 37879, 37890, (June 19, 2000) (discussing this issue in final redesignation of Cincinnati, Ohio 1-hour ozone nonattainment area); and 66 FR 50399 (October 19, 2001) (final redesignation of Pittsburg, Pennsylvania 1-hour ozone nonattainment area).

[20] See 76 FR 14584.

[21] Available in the docket for this proposed rulemaking.

[22] A detailed rationale for this view is described in the memorandum from Mary Nichols, Assistant Administrative for Air and Radiation, dated October 14, 1994, entitled, ''Part D New Source Review Requirements for Areas Requesting Redesignation to Attainment.''

section 110(a)(2). EPA believes Montana's June 24, 2020 SIP submission pertaining to the Libby Area meets the requirements of section 110(a)(2).

4. Subpart 1, Section 176 Conformity Requirements

Section 176(c) of the CAA requires states to establish the criteria and procedures to ensure that federally supported or funded projects conform to the air quality planning goals in the applicable SIP. The requirement to determine conformity applies to transportation plans, programs and projects that are developed, funded, or approved under title 23 of the United States Code (U.S.C.) and the Federal Transit Act (transportation conformity) as well as to other federally supported or funded projects (general conformity). State transportation conformity SIP revisions must be consistent with federal conformity regulations relating to consultation, enforcement, and enforceability that EPA promulgated pursuant to its authority under the CAA.

Although EPA interprets the conformity SIP requirements [23] as not applying for purposes of evaluating the redesignation request under section 107(d)(3) [24] we note that Montana has an approved conformity SIP. See 66 FR 48561 (September 21, 2001).

5. Subpart 4 Requirements

As discussed in Section I of this document, in *NRDC* v. *EPA*, the D.C. Circuit held that EPA should have implemented the 1997 $PM_{2.5}$ annual NAAQS pursuant to the particulate matter-specific provisions of Subpart 4. On remand, EPA identified all areas designated nonattainment for either the 1997 or the 2006 $PM_{2.5}$ NAAQS, including the Libby Area, as Moderate nonattainment for purposes of Subpart 4 in the Classifications and Deadlines Rule. Moderate nonattainment areas are subject to the requirements of CAA sections 189(a), (c), and (e), including: (1) an approved permit program for construction of new and modified major stationary sources (section 189(a)(1)(A)); (2) an attainment demonstration, (section 189(a)(1)(B)); (3) provisions for RACM (section 189(a)(1)(C)); (4) quantitative milestones demonstrating RFP toward attainment by the applicable attainment date (section 189(c)); and (5) precursor control (section 189(e)).

With respect to the specific attainment planning requirements under Subpart 4,[25] EPA applies the same interpretation that it applies to attainment planning requirements under Subpart 1 or any other pollutant-specific subparts. That is, under its long-standing interpretation of the CAA, where an area is already attaining the standard, EPA does not consider those attainment planning requirements to be applicable for purposes of evaluating a request for redesignation, that is, CAA section 107(d)(3)(E)(ii) or (v), because requirements that are designed to help an area achieve attainment no longer have meaning where an area is already meeting the standard. EPA is therefore proposing to determine that the specific attainment planning requirements under Subpart 4 are not applicable for evaluating Montana's redesignation request.

CAA section 189(e) provides that control requirements for major stationary sources of direct PM_{10} (including $PM_{2.5}$) shall also apply to particulate matter precursors from those sources, except where EPA determines that major stationary sources of such precursors do not contribute significantly to PM_{10} levels that exceed the standard in the area. The CAA does not explicitly address whether it would be appropriate to include a potential exemption from precursor controls for all source categories under certain circumstances. In implementing Subpart 4 with regard to controlling PM_{10}, EPA permitted states to determine that a precursor was ''insignificant'' where the state could show in its attainment plan that it would expeditiously attain without adoption of emission reduction measures aimed at that precursor. This approach was upheld in the *Association of Irritated Residents* v. *EPA,* 423 F.3d 989 (9th Cir. 2005) and extended to $PM_{2.5}$ implementation in the $PM_{2.5}$ SIP Requirements Rule. A state may develop its attainment plan and adopt RACM that target only those precursors that are necessary to control for purposes of timely attainment. *See* 81 FR 58010 at 58020 (August 24, 2016).

For the Libby Area, a precursor exemption analysis under section 189(e) and EPA's implementing regulations is not an applicable requirement that needs to be fully approved in the context of a redesignation under CAA section 107(d)(3)(E)(ii) since the Area is already in attainment which demonstrates that precursors contribution is insignificant. Therefore, measures aimed at the precursors are not needed.

As discussed previously in this document, for areas that are attaining the standard, EPA does not interpret attainment planning requirements of Subparts 1 and 4 to be applicable requirements for purposes of redesignating an area to attainment. On July 14, 2015, EPA approved that the Libby Area had attained the 1997 annual $PM_{2.5}$ NAAQS by the Area's statutory attainment date. The Libby Area has expeditiously attained the 1997 annual $PM_{2.5}$ NAAQS, and therefore, no additional controls of any pollutant, including any $PM_{2.5}$ precursor, are necessary to bring it into attainment. In section V of this document, we find that the Libby Area continues to attain the NAAQS. EPA has determined that the Libby Area has attained the standard due to permanent and enforceable emissions reductions. Further, as set forth in section IV.C of this document, we believe that the Libby $PM_{2.5}$ LMP demonstrates continued maintenance of the 1997 annual $PM_{2.5}$ NAAQS standard through 2031 which also demonstrates that the $PM_{2.5}$ precursors are insignificant. Taken together, these factors support our conclusion that $PM_{2.5}$ precursors are adequately controllable.

B. Has the state demonstrated that air quality improvement is due to permanent and enforceable reductions?

In order to approve a redesignation from nonattainment to attainment, section 107(d)(3)(E)(iii) of the CAA requires EPA to determine that the improvement in air quality is due to emission reductions that are permanent and enforceable, and that the improvement results from the implementation of the applicable SIP and applicable federal air pollution control regulations and other permanent and enforceable regulations. Under this criterion, a state must be able to reasonably attribute the improvement in air quality to emissions reductions that are permanent and enforceable. Attainment resulting from temporary reductions in emission rates (*e.g.,* reduced production or shutdown due to temporary adverse economic conditions) or unusually favorable meteorology would not qualify as an air quality improvement due to permanent and enforceable emission reductions. See Calcagni Memorandum at 4. In its demonstration that improvements in air quality are reasonably attributable to emissions reductions that are permanent

[23] CAA section 176(c)(4)(E) requires states to submit revisions to their SIPs to reflect certain federal criteria and procedures for determining transportation conformity.

[24] EPA believes that this interpretation is reasonable because state conformity rules are still required after redesignation and federal conformity rules apply where states rules have not been approved. *See Wall* v. *EPA,* 265 F.3d 426 (6th Cir., 2001) (upholding this interpretation); 60 FR 62748 (December 7, 1995).

[25] These planning requirements include the attainment demonstration, qualitative milestone requirements, and RACM analysis.

and enforceable, Montana evaluated several factors:[26] the composition of $PM_{2.5}$ in the nonattainment area; control measures that have been implemented since the area was redesignated to nonattainment; changes to the emissions inventory over time; and meteorological and economic trends. In its evaluation, Montana identified two fugitive area sources contributing to $PM_{2.5}$ concentrations in the nonattainment area: wood combustion and tailpipe emissions. Eighty-two percent of the $PM_{2.5}$ concentrations during the baseline study year of 2005 was attributed to wood combustion. Wood combustion impacts represented both residential and small commercial space heating, and outdoor burns. The State identified emission reductions from only the wood combustion category in the attainment plan; the plan did not take credit for reductions from mobile source tailpipe emissions due to federal tailpipe standards or fleet turnover.

In its approved Moderate nonattainment plan, Montana adopted permanent and enforceable rules from the Lincoln County Air Pollution Control Program. This program includes rules that reduce $PM_{2.5}$ impacts in the nonattainment area resulting in attainment of $PM_{2.5}$ NAAQS.[27] The air pollution control rules in Chapter 1, Subchapters 1 through 4 of the Lincoln County Air Pollution Control Program, address solid fuel burning devices, re-entrained road dust control, and outdoor burning regulations. These rules are part of the Lincoln County Health Department's Health and Environmental Rules in Chapter 1. The rules contain the following subchapters, all designed to help Lincoln County attain the $PM_{2.5}$ NAAQS:

- Subchapter 1—(75.1.100–106)—General Provisions;
- Subchapter 2—(75.1.200–206,208)—Solid Fuel Burning Device Regulations;
- Subchapter 3—(75.1.301–308)—Dust Control Regulations; and
- Subchapter 4—(75.1.401–408)—Outdoor Burning Regulations.

The regulations in Lincoln County's Subchapter 2 require that solid fuel burning devices be permitted by the Lincoln County Environmental Health Department. The regulations restrict the material allowed for combustion and prohibit visible emissions greater than 20 percent opacity. Lincoln County will call Air Pollution Alerts[28] when particulate matter concentrations are more than 80 percent of the 24-hour standard and at that time, solid fuel burning devices are not allowed to operate unless the device has received an exemption. A provision allows exempt devices to be operated during an alert, but only with an opacity of 10 percent or less.

Although re-entrained road dust is not an identified emission source category, Subchapter 3 of the Lincoln County rules address re-entrained dust from roads, parking lots and commercial lots by requiring dust abatement and control. These road dust regulations apply within the regulated road sanding and sweeping district as defined in the regulation. Vehicular operations within the district are only allowed on paved surfaces within the district. To control ice on the roads, liquid de-icing agents and de-icing salts should be used. Sanding material is not allowed unless the Lincoln County Environmental Health Department declares an emergency and then only sanding material that meets specific durability, abrasion, and fine concentrations are allowed. Roads are to be maintained using a schedule of prioritized street sweeping and flushing to remove carry-on or applied materials. Commercial operations shall also implement measures to prevent depositing material on yards/lots, suppress dust, and clean adjoining roadways.

Lincoln County's Subchapter 4 addresses outdoor burning and restricts non-essential outdoor burning, promoting alternative disposal methods and recycling, and setting standards to minimize emissions when outdoor burning is necessary. These rules apply to both the air pollution control district which is the same area as the Libby nonattainment area, and the Impact Zone L, which extends beyond the nonattainment area. The rules specify which materials and activities are prohibited for outdoor burning. Residential outdoor burning is only allowed in the month of April while management burns are allowed from April through October. Burning outside these months requires additional approval from the Lincoln County Health Department. Burners must obtain a burn permit from the Department and may only conduct their burn if meteorological conditions have good air dispersion characteristics, as determined by the Department.

Montana has determined that most of the emissions reductions from the wood combustion source category are attributed to the Lincoln County residential wood combustion rules. These rules control residential and small commercial wood combustion used for space heating through a wood stove permit program. The rules restrict the installation and operation of wood stoves to times with good air quality dispersion. Lincoln County also has outdoor open burning rules that require burns to be permitted and approved to ensure the burns occur during favorable meteorological conditions.

Montana evaluated emissions from residential wood burning contributing to $PM_{2.5}$ in Libby, Montana. Table 2.3 in the June 24, 2020 Libby Area SIP submission displays the 2005 actual annual emissions, which are considered the annual baseline emissions for Libby. Additionally, the table shows the annual emissions from the 2014 National Emissions Inventory (NEI). As shown in the Table 2.3, emissions for residential wood burning in 2014 have decreased more than 85 percent compared to the baseline emissions in 2005. The total emissions for area source categories for 2014 total emissions have decreased more than 62 percent compared to the 2005 baseline emissions.

In addition, Montana has adopted permitting requirements for major stationary sources or major modifications located in the nonattainment areas including Libby, Montana. They are located in the Administrative Rules of Montana (ARM) 17.8.901 through 17.8.906. These rules require all new sources or modifications to use the lowest achievable emission rate (LAER). Sources must obtain emission reduction offsets in tons per year (tpy) which provide a positive net air quality benefit in the nonattainment area using a one to one offset and must be from the same source or another emissions source within the same nonattainment area. There must be demonstrated improvement to the $PM_{2.5}$ nonattainment with permanent, quantifiable, and federally enforceable reductions. A reduction of actual emissions, not potential emissions, must occur before a new source can be permitted to operate.

In addition, Montana has a federally enforceable permitting program for minor sources in ARM, Title 17 Chapter 8, Subpart 7 that addresses $PM_{2.5}$ emissions. These rules require sources that emit 25 tpy or more of $PM_{2.5}$ to ensure the nonattainment area is not negatively affected. Beginning in May 2019, Montana began requiring registration of all sized asphalt plants, concrete plants, mineral crushers, and

[26] See Montana's attainment plan for the Libby Area, approved on March 17, 2011 (76 FR 14584).

[27] *See* Section 1.3 in the Libby Area SIP submission. Available in the docket for this proposed rulemaking.

[28] See 75.1.206, Lincoln County Air Pollution Control Program.

mineral screens. The registration program establishes conservative operational restrictions on these portable sources to prevent degradation of the air quality in nonattainment areas and elsewhere.

Not only has air quality in the Libby Area benefited from the local district and State rules discussed previously, but the Area has also benefitted from emission reductions from federal measures including federal tailpipe standards and the Federal Motor Vehicle Control Program. Federal tailpipe standards were designed to reduce vehicle emissions, including $PM_{2.5}$. The previous control plan did not take credit for the $PM_{2.5}$ reductions resulting from lower federal vehicle emissions standards and vehicle fleet turnover in the nonattainment area. The federal tailpipe standards and vehicle turnover will continue to reduce future impacts and meet the requirements of the 1990 CAA Amendments. The Federal Motor Vehicle Control Program controls tailpipe emissions and evaporative emission standards for new vehicles. Tailpipe impacts were less than one percent of the Libby Area during the 2005 baseline year.[29] The $PM_{2.5}$ impact reductions are supported by lower fleet vehicle fleet emissions as fleet turnover continues.

Based upon the previously listed actions by Montana in the submitted maintenance plan, EPA finds that the improvement in air quality in the Libby Area is the result of permanent and enforceable emissions reductions from a combination of EPA-approved local and State control measures and federal control measures. As such, we believe the criterion for redesignation set forth in CAA section 107(d)(3)(E)(iii) is satisfied.

C. Does the Area have a fully approved maintenance plan pursuant to section 175A of the CAA?

For redesignating a nonattainment area to attainment, the CAA requires EPA to determine that the area has a fully approved maintenance plan pursuant to section 175A of the CAA (CAA section 107(d)(3)(E)(iv)). In conjunction with its request to redesignate the Libby Area to attainment for the 1997 annual $PM_{2.5}$ NAAQS, Montana submitted a SIP revision to provide for the maintenance of the 1997 annual $PM_{2.5}$ NAAQS for at least 10 years after the effective date of redesignation to attainment. EPA believes that this maintenance plan meets the requirements for approval under section 175A of the CAA for the reasons discussed in this section.

Section 175A of the CAA sets forth the elements of a maintenance plan for areas seeking redesignation from nonattainment to attainment. Under section 175A, the plan must demonstrate continued attainment of the applicable NAAQS for at least 10 years after the Administrator approves a redesignation to attainment. Because the 1997 primary annual $PM_{2.5}$ NAAQS will be revoked for the Libby Area if it is redesignated to attainment, Montana is not required to submit a second 10-year maintenance plan for the 1997 primary annual $PM_{2.5}$ NAAQS. *See* 81 FR 58010, 58144. To address the possibility of future NAAQS violations, the maintenance plan must contain such contingency measures, as EPA deems necessary, to assure prompt correction of any future 1997 annual $PM_{2.5}$ NAAQS violations. The Calcagni Memorandum provides further guidance on the content of a maintenance plan, explaining that a maintenance plan should address five requirements: the attainment emissions inventory; maintenance demonstration; monitoring; verification of continued attainment; and a contingency plan. As is discussed here, EPA finds that Montana's maintenance plan includes all the necessary components and is thus proposing to approve it as a revision to the Montana SIP.

1. Attainment Emissions Inventory

As discussed previously, EPA is proposing to determine that the Libby Area is attaining the 1997 annual $PM_{2.5}$ NAAQS based on a monitoring data for the time period from 2014–2021. Montana selected 2014 as the attainment emission inventory year. The attainment inventory identifies the level of emissions in the Area that is sufficient to attain the 1997 annual $PM_{2.5}$ NAAQS. Montana began development of the attainment inventory by first generating a baseline emissions inventory for the Libby Area. Montana selected 2005 as the base year for developing a comprehensive emissions inventory for direct $PM_{2.5}$ and the $PM_{2.5}$ precursors SO_2, NO_X, VOCs, and ammonia. See 76 FR 14584 (March 17, 2011). The Wegman Memorandum states that an attainment inventory should represent emissions during the same 5-year period associated with the air quality data used to determine that the area meets the applicability requirements of the LMP option. The Libby LMP, provided in Montana's June 24, 2020 SIP submission, includes an emission inventory from 2014, representative of the 2014–2021 time period which served as the 5-year period relied upon in limited maintenance plans as meeting the air quality data requirements of the Wegman Memorandum.[30]

2. Maintenance Demonstration

Montana's SIP submission for the Libby Area employs the CDV method laid out in the 2001 Wegman Memorandum to demonstrate that the Area is eligible for an LMP. As noted previously, the CDV calculation from the Wegman Memorandum represents the highest design value an area could have before it would violate the NAAQS given a 1 in 10 probability—that is, if the area's current ADV (based on the most recent five years of data) is less than the CDV, there is a less than 1 in 10 probabilities that the area will violate in the future. The State's submission calculates the ADV as 10.9 $\mu g/m^3$ and calculates the site-specific CDV as 14.1 $\mu g/m^3$ using the Libby Area monitor data from 2014–2018. Therefore, the State's submission showed the Libby ADV is less than the CDV, but because of the time that has elapsed since the State's submission, EPA has also analyzed more recent data that are available in AQS and have been certified by the MDEQ.

To calculate the ADV we averaged the most recent five design values for the $PM_{2.5}$ annual standard. Since each design value is calculated by averaging three years of valid annual means, the average of the last five design values includes data from the most recent 7-year period (2014–2021). Table 3 presents the most recent annual $PM_{2.5}$ NAAQS design values for 2017–2021 and presents the resulting ADV of 13.2 $\mu g/m^3$.

To calculate the CDV we use the most recent five years of design values and their variability with the equation presented in the Wegman Memorandum (Table 3). The resulting site-specific CDV is calculated to be 14.6 $\mu g/m^3$ (Table 5). Therefore, the ADV (13.2 $\mu g/m^3$) falls below the site-specific CDV of

[29] *See* Table 2.3 in the Libby Area SIP submission. Available in the docket for this proposed rulemaking.

[30] The emissions inventory included in the Libby Area SIP submission is the 2014 NEI. The NEI is a composite of data from many different sources, with PM data coming primarily from EPA models as well as from state, tribal, and local air quality management agencies. Different data sources use different data collection methods, and many of the emissions data are based on estimates rather than actual measurements. EPA considers the 2014 NEI representative of the period from 2014–2021 because Montana provided comparable vehicle miles traveled (VMT) data in their submission. *See* Libby Area SIP submission, Appendix A, Montana Department of Transportation Future VMT Projections, p. A–1 in docket for this proposed rulemaking.

14.6 $\mu g/m^3$ and thus meets the first criterion for LMP eligibility.[31]

TABLE 3—ANNUAL $PM_{2.5}$ NAAQS DESIGN VALUES ($\mu g/m^3$) [32]

2017 Design value (2015–2017) *	2018 Design value (2016–2018) *	2019 Design value (2017–2019) *	2020 Design value (2018–2020) *	2021 Design value (2019–2021) *	Average of most recent 3-year design values (ADV)
13.0	12.9	13.4	13.3	13.3	13.2

TABLE 4—ELIGIBILITY CALCULATION EQUATIONS

Critical Design Value	$CDV = NAAQS/(1 + (t_c \times CV))$
Coefficient of Variation	$CV = \sigma/ADV$
Projected DV due to Motor Vehicle Growth over 10 years	Projected $DV = ADV + (VMT_{pi} \times DV_{mv})]$

ADV = Average of 3-year design values.
DV = Design value.
DV_{mv} = motor vehicle design value based on on-road mobile portion of the attainment year inventory.
NAAQS = Applicable standard (15 $\mu g/m^3$).
σ = standard deviation of design values.
t_c = Critical t-value (based on the one-tail student's t-distribution, at a significance level of 0.10).
VMT_{pi} = Projected percent increase in vehicle miles traveled (VMT) over the next 10 years.

TABLE 5—CALCULATION OF THE CDV USING 2017–2021 DESIGN VALUES

NAAQS	15.0 $\mu g/m^3$
T_c	1.533
ADV (2017–2021)	13.2 $\mu g/m^3$
Σ	0.2168 $\mu g/m^3$
CV	0.0164
$CDV = [NAAQS/(1 + t_c \times CV)]$	14.6 $\mu g/m^3$

In addition to having an ADV that is at or below the site-specific CDV, the 2001 Wegman Memorandum also provides a methodology for calculating a margin of safety factor based on expected growth in mobile source emissions. The memo lays out in Attachment B a motor vehicle regional emissions analysis test, which is designed to account for an area's expected change in vehicle miles traveled, to determine whether increased emissions from on-road mobile sources could, in the next 10 years, increase concentrations in the area and threaten the assumption of maintenance that underlies LMP policy. In its June 24, 2020 SIP submission, Montana employed the motor vehicle regional emissions analysis test outlined in Attachment B of the Wegman Memorandum to demonstrate that the Libby Area's expected growth in mobile source emissions would not threaten maintenance of the NAAQS. Using data from 2014–2018 the State calculated that due to growth in mobile source emissions the ADV may increase from 10.9 $\mu g/m^3$ to 11.1 $\mu g/m^3$ in the next 10 years, but that 11.1 $\mu g/m^3$ is still below the margin of safety as defined by the site-specific CDV (14.1 $\mu g/m^3$). EPA has also examined more recent data to confirm that even with updated information, the test continues to show that anticipated growth in mobile source emissions should not interfere with the Libby Area's maintenance of the 1997 annual $PM_{2.5}$ NAAQS. Using design values from 2017–2021, we calculated that due to expected growth in mobile source emissions, the ADV may increase from 13.2 $\mu g/m^3$ to 13.5 $\mu g/m^3$ in the next 10 years, but that 13.5 $\mu g/m^3$ is still below the margin of safety as defined by the site-specific CDV (14.6 $\mu g/m^3$). For the calculations used to determine how the Libby Area passed the motor vehicle regional analysis test, see Table 6.[33]

TABLE 6—MOTOR VEHICLE REGIONAL EMISSIONS ANALYSIS TEST CALCULATIONS

ADV (2017–2021)	13.2 $\mu g/m^3$
VMT_{pi}	11.56%
DV_{mv}	2.5 $\mu g/m^3$
Calculated $[ADV + (VMT_{pi} \times DV_{mv})]$	13.5 $\mu g/m^3$

The 2001 Wegman Memorandum also indicates that once a state has an approved LMP, the state will be expected to determine, on an annual basis, that the LMP criteria are still being met. If the state determines that the LMP criteria are not being met, it should take action to reduce $PM_{2.5}$ concentrations enough to requalify for the LMP. One possible approach a state could take is to implement contingency measures. For a description of contingency provisions included in the Libby LMP, see section 3.6 of Montana's June 24, 2020 SIP submission.

Although the State flagged some $PM_{2.5}$ values as potentially affected by exceptional events, such as wildfire

[31] *See* Libby $PM_{2.5}$ CDV Calculations in docket for this proposed rulemaking.

[32] In Table 3, (years)* is referring to what data was included in the calculation for each 3-year design value.

[33] *See* Memo to File, Libby MT Motor Vehicle Regional Emission Analysis in docket for this proposed rulemaking.

smoke, this action utilizes all quality-assured monitoring data from Libby. A 2019 memo from Richard Wayland and Anna Wood regarding additional methods, determinations, and analyses to modify air quality data beyond exceptional events,[34] indicates that monitoring data could qualify for exclusion for use in calculating air quality design values in support of a NAAQS LMP submission and any subsequent yearly design value calculations for areas with approved LMPs. The memorandum states that such data exclusion requests will be treated in a manner analogous to the treatment of exceedance data under the Exceptional Events Rule (EER). Since the Libby Area qualifies for the LMP option without the removal of any demonstrated values, the flagged data have no regulatory significance and therefore the demonstrated values are included in the calculations and remain in AQS. Additional information on the EER can be found in 40 CFR 50.14 and 40 CFR 51.930.

Pursuant to the Wegman Memorandum, the State's approved maintenance plan should include an emissions inventory (attainment inventory) which can be used to demonstrate attainment of the NAAQS. The inventory should represent emissions during the same 5-year period associated with air quality data used to determine whether the area meets the applicability requirements of the LMP option. The state should review its inventory every three years to ensure emissions growth is incorporated in the attainment inventory, if necessary. In this instance, Montana completed an attainment year inventory for 2014 for the Libby Area. EPA has reviewed the 2014 emissions inventories and determined that they are appropriate for this plan.

3. Monitoring Network

The $PM_{2.5}$ monitoring network for the Libby Area has been developed and maintained in accordance with federal siting and design criteria in 40 CFR part 58, appendices D and E and in consultation with EPA Region 8. In section 3.5 of the Libby LMP, located within Montana's June 24, 2020 SIP submission, Montana states that it will continue to operate its monitoring network to meet EPA requirements at 40 CFR part 58 and identify any issues or adjustments via the annual Ambient Air Monitoring Network Plan or formal communication. EPA approved Montana's 2021 monitoring plan on November 16, 2021.[35]

4. Verification of Continued Attainment

Montana, through MDEQ, has the legal authority to enforce and implement the requirements of the Libby LMP. This includes the authority to adopt, implement, and enforce any subsequent emissions control contingency measures determined to be necessary to correct future $PM_{2.5}$ attainment problems.

In demonstrating maintenance, continued attainment of the NAAQS can be verified through operation of an appropriate air quality monitoring network. The Calcagni Memorandum (p.11) states that the maintenance plan should contain provisions for continued operation of air quality monitors that will provide such verification. As discussed in section V of this document, $PM_{2.5}$ is currently monitored by MDEQ within the Libby Area. In section 3.5 of Montana's submitted maintenance plan, MDEQ intends to maintain an appropriate $PM_{2.5}$ monitoring network and review monitoring and emissions data through the maintenance period.

MDEQ will track the progress of the maintenance plan by performing future reviews of triennial emission inventories for the Libby Area as required in the Air Emissions Reporting Rule (AERR). Emissions information will be compared to the attainment year to assure continued compliance with the annual $PM_{2.5}$ standard.

5. Contingency Provisions

Section 175A(d) of the CAA requires that the maintenance plan contains contingency provisions to assure that the state will promptly correct any violation of the relevant $PM_{2.5}$ NAAQS that may occur after the redesignation of the area to attainment. Such provisions must include a requirement that the state will implement all measures with respect to the control of the air pollutant concerned that were contained in the SIP for the area before redesignation of the area as an attainment area. EPA's redesignation guidance notes that the state is not required to have fully adopted contingency measures that will take effect without further action by the state. As such, the contingency plan should ensure that the state has the capacity to adopt the contingency measures expediently if the need were triggered. Therefore, the primary elements of this contingency plan involve the tracking and triggering mechanisms to determine when contingency measures would be necessary and a process for implementing appropriate control measures.

Montana will continue to monitor and analyze $PM_{2.5}$ concentrations to determine continued maintenance of the relevant $PM_{2.5}$ NAAQS. In accordance with 40 CFR part 58, MDEQ will continue to operate the Libby monitor (Site ID 30–053–0018).

If the State determines the Libby Area has exceeded the 1997 annual $PM_{2.5}$ NAAQS, the triggering of the contingency plan does not automatically require a revision of the SIP, nor is the Area necessarily redesignated once again to nonattainment. Instead, MDEQ will have an appropriate timeframe to correct the violation with implementation of one or more adopted contingency measures. If violations continue to occur, additional contingency measures may need to be adopted until the violations are corrected.

Montana has adopted a contingency provision to address future $PM_{2.5}$ air quality problems. The contingency provisions in the Libby $PM_{2.5}$ LMP are contained in section 3.6. of Montana's June 24, 2020, SIP submission. MDEQ identifies the following steps if a violation occurs, and the State triggers the contingency plan:

1. Within 12 months of an exceedance notification, MDEQ and the local government in the Libby Area will commence an analysis to review information about historical exceedances of the standard, the meteorological conditions related to recent exceedance(s), most recent growth, and emissions, and if the possibility of an exceptional event occurred. MDEQ will develop appropriate contingency measure(s) to correct the violation of the $PM_{2.5}$ standard.

2. Under the 2016 revisions to the Treatment of Data Influenced by Exceptional Events Rule (81 FR 68216), MDEQ will confer with EPA Region 8 regarding whether any flagged exceptional events would meet the criteria of a regulatory decision, and if so, a determination would be made on whether to move forward with producing a demonstration and if that would trigger contingency measures.

3. If MDEQ and the local government in the Libby Area finds locally adopted control measures to be inadequate, MDEQ and the local government will adopt state-enforceable measures as deemed necessary by MDEQ to prevent additional exceedances or violations.

[34] *See* the memorandum from Richard Wayland, Director of Air Quality Assessment Division and Anna Marie Wood, Director of Air Quality Policy Division, dated April 4, 2019, entitled, ''Additional Methods, Determinations, and Analyses to Modify Air Quality Data Beyond Exceptional Events.''

[35] *See* MT AMNP Approval Letter 2021 in docket for the proposed rulemaking.

Measures to be considered include implementation of Libby's Contingency Rules 75.1.208 and 75.1.307, as spelled out in Montana's Libby $PM_{2.5}$ attainment plan, the use of deciphers, additional street cleaning, etc.

Upon our review, we find that the contingency provisions of the Libby $PM_{2.5}$ LMP satisfy the pertinent requirements of section 175A of the CAA.

D. Transportation and General Conformity

The requirements for transportation and general conformity are found in CAA section 176(c). Conformity to the SIP means that transportation-related actions (transportation conformity) and other federal actions (general conformity) will not cause or contribute to any new violation of any standard in any area, increase the frequency or severity of any existing violation of any standard in any area or delay timely attainment of any standard or any required interim emission reductions or other milestones in any area (CAA section 176(c)(1)(B)).

As discussed in section II.B, if the proposal is finalized, the 1997 primary annual $PM_{2.5}$ NAAQS will be revoked in the Libby Area on the effective date of the redesignation. Beginning on that date, the Area will no longer be subject to transportation conformity or general conformity requirements for the 1997 annual $PM_{2.5}$ NAAQS due to the revocation of the 1997 primary annual $PM_{2.5}$ NAAQS. See 81 FR 58125–6.

V. What are the effects of EPA's proposed actions?

EPA's proposed actions establish the basis upon which EPA may take final action on the issues being proposed for approval. Approval of Montana's redesignation request would change the legal designation of Lincoln County for the 1997 annual $PM_{2.5}$ NAAQS, found at 40 CFR part 81, from nonattainment to attainment. The limited maintenance plan includes contingency measures to remedy any future violations of the 1997 annual $PM_{2.5}$ NAAQS and procedures for evaluation of potential violations.

VI. Proposed Actions

EPA is proposing to: (1) determine that the Libby Area is attaining the 1997 annual $PM_{2.5}$ NAAQS based on 2014–2021 data; (2) approve Montana's plan for maintaining the 1997 annual $PM_{2.5}$ NAAQS (limited maintenance plan); and (3) redesignate the Libby Area to attainment for the 1997 annual $PM_{2.5}$ NAAQS. If finalized, approval of the redesignation request would change the official designation of Lincoln County for the 1997 annual $PM_{2.5}$ NAAQS, found at 40 CFR part 81 from nonattainment to attainment, as found at 40 CFR part 81.

VII. Statutory and Executive Order Reviews

Under the CAA, redesignation of an area to attainment and the accompanying approval of a maintenance plan are actions that affect the status of a geographical area and do not impose any additional regulatory requirements on sources beyond those imposed by state law. A redesignation to attainment does not in and of itself create any new requirements, but rather results in the applicability of requirements contained in the CAA for areas that have been redesignated to attainment. Moreover, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely proposes to approve state law as meeting federal requirements and does not impose additional requirements beyond those imposed by state law. For these reasons, this proposed action:

- Is not a ''significant regulatory action'' subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Public Law 104–4);
- Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and
- 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 program, policies, and activities on minority populations (people of color/Indigenous people) and low-income populations.

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

List of Subjects

40 CFR Part 52

Environmental protection, Air pollution control, Carbon monoxide, Greenhouse gases, Incorporation by reference, Intergovernmental relations, Lead, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

40 CFR Part 81

Environmental protection, Air pollution control, National parks, and Wilderness areas.

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

Dated: December 1, 2022.

KC Becker,

Regional Administrator, Region 8.

[FR Doc. 2022–26504 Filed 12–5–22; 8:45 am]

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 622

[Docket No. 221130–0256]

RIN 0648–BL29

Fisheries of the Caribbean, Gulf of Mexico, and South Atlantic; Reef Fish Fishery of the Gulf of Mexico; Vermilion Snapper Harvest Levels

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

ACTION: Proposed rule; request for comments.

SUMMARY: NMFS proposes to implement management measures described in a framework action under the Fishery Management Plan for the Reef Fish Resources of the Gulf of Mexico (FMP), as prepared by the Gulf of Mexico Fishery Management Council (Council). If implemented, this proposed rule would increase catch levels for vermilion snapper in the Gulf of Mexico (Gulf). The purpose of this proposed rule is to prevent overfishing of Gulf vermilion snapper and to achieve optimum yield (OY).

DATES: Written comments must be received on or before January 5, 2023.

ADDRESSES: You may submit comments on the amendment identified by ''NOAA–NMFS–2022–0099'' by either of the following methods:

Electronic Submission: Submit all electronic public comments via the Federal e-Rulemaking Portal. Go to *https://www.regulations.gov* and enter ''NOAA–NMFS–2022–0099'', in the Search box. Click the ''Comment'' icon, complete the required fields, and enter or attach your comments.

Mail: Submit written comments to Rich Malinowski, Southeast Regional Office, NMFS, 263 13th Avenue South, St. Petersburg, FL 33701.

Instructions: Comments sent by any other method, to any other address or individual, or received after the end of the comment period, may not be considered by NMFS. All comments received are a part of the public record and will generally be posted for public viewing on *www.regulations.gov* without change. All personal identifying information (*e.g.,* name, address, etc.), confidential business information, or otherwise sensitive information submitted voluntarily by the sender will be publicly accessible. NMFS will accept anonymous comments (enter ''N/A'' in the required fields if you wish to remain anonymous).

Electronic copies of the framework action, which includes an environmental assessment, a fishery impact statement, a Regulatory Flexibility Act (RFA) analysis, and a regulatory impact review, may be obtained from the Southeast Regional Office website at *https://www.fisheries.noaa.gov/action/modification-gulf-mexico-vermilion-snapper-overfishing-limit-acceptable-biological-catch-and?check_logged_in=1.*

FOR FURTHER INFORMATION CONTACT: Rich Malinowski, Southeast Regional Office, NMFS, telephone: 727–824–5305; email: *rich.malinowski@noaa.gov.*

SUPPLEMENTARY INFORMATION: NMFS and the Council manage the Gulf reef fish fishery, which includes vermilion snapper, under the FMP. The Council prepared the FMP and NMFS implements the FMP through regulations at 50 CFR part 622 under the authority of the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act).

Background

The Magnuson-Stevens Act requires NMFS and regional fishery management councils to prevent overfishing and achieve, on a continuing basis, the OY from federally managed fish stocks. These mandates are intended to ensure fishery resources are managed for the greatest overall benefit to the nation, particularly with respect to providing food production and recreational opportunities, and protecting marine ecosystems.

All weights described in this proposed rule are in round weight.

In 2012, the Generic Annual Catch Limits and Accountability Measures Amendment (76 FR 82044, December 29, 2011) for the Gulf established catch limits for vermilion snapper including the overfishing limit (OFL), acceptable biological catch (ABC), and annual catch limit (ACL). Amendment 47 to the FMP (83 FR 22210, May 14, 2018) specified the proxy for maximum sustainable yield (MSY) as the yield when fishing at a mortality rate corresponding to 30 percent spawning potential ratio ($F_{30\%}$ SPR) and decreased the vermilion snapper OFL, ABC, and ACL based on the results of the 2016 Southeast Data Assessment Review (SEDAR) stock assessment (SEDAR 45), and the recommendations of the Council's Scientific and Statistical Committee (SSC). The SSC recommended a declining OFL derived from fishing at the MSY proxy. The OFL for 2021 and beyond specified in Amendment 47 is 3,490,000 lb (1,583,037 kg). The SSC also provided two recommendations for ABC: one derived from fishing at 75% of the MSY proxy, which declined from 2017 through 2021, and one derived using the average of the 2017–2021 ABCs, which resulted in a constant ABC. The Council chose to adopt the constant catch ABC of 3,110,000 lb (1,410,672 kg), and set the ACL equal to the ABC. Vermilion snapper annual landings have been less than this ACL since the implementation of the stock ACL in 2012, with the exception of 2018 when it was exceeded by 3 percent.

In 2020, a new assessment (SEDAR 67) was completed for vermilion snapper using data through the 2017 fishing year. The SEDAR 67 results indicate the stock is not overfished and not experiencing overfishing. SEDAR 67 included new data sources, including historical recreational catch and effort data adjusted to be consistent with the Marine Recreational Information Program (MRIP) Fishing Effort Survey (FES). MRIP transitioned from the legacy Coastal Household Telephone Survey (CHTS) to the new FES mail survey. The FES was launched in 2015, and replaced the CHTS in 2018. Both survey methods collect data needed to estimate marine recreational fishing effort by private anglers on the Atlantic and Gulf coasts. The CHTS used random-digit dialing of homes in coastal counties to contact fishermen. The new mail-based FES uses fishing license and registration information as one way to identify and contact fishermen (supplemented with data from the U.S. Postal Service). MRIP–FES landings estimates are generally greater than those generated by MRIP–CHTS and NMFS developed a calibration model to allow estimates produced by either survey to be adjusted to be consistent with the estimates produced by the other survey.

To determine how inclusion of FES-adjusted landings estimates in SEDAR 67 impacted the catch projections for vermilion snapper, the previously accepted assessment model used in SEDAR 45 was updated using the FES data. The same 5-year (2017–2021) average used to set the current ABC was applied to the revised SEDAR 45 projections. This resulted in an FES-based OFL estimate of 6,760,000 lb (3,066,284 kg), which is almost double the current OFL of 3,580,000 lb (1,623,861 kg). Thus, using FES landings estimates in the SEDAR 45 model indicates that the OFL would have been much higher had the FES data been available at the time the previous assessment was completed.

The SSC reviewed SEDAR 67, agreed that vermilion snapper is not overfished or undergoing overfishing, and reviewed the SEDAR 67 projections. Due to the uncertainty in the SEDAR 67 assessment and recent recruitment, the SSC determined that the catch levels should be based on the average of the projections from 2021–2025, and recommended an increase in the OFL to 8,600,000 lb (3,900,894 kg) and an increase in the ABC to 7,270,000 lb (3,297,617 kg).

The Council's Reef Fish Advisory Panel (AP) reviewed the SSC recommendations and expressed concerns about setting the ACL equal to the ABC, noting that recent landings have been relatively low. Using MRIP–FES estimates, recreational landings from 2012 through 2020 have generally been below 4,000,000 lb (1,814,369 kg), with the highest landings occurring in 2018 at approximately 4,380,000 lb (1,986,735 kg). The AP recommended that the stock ACL be set at 75 percent of the ABC and the Council agreed with the AP's recommendation. Based on the recommendations from the SSC and the AP the Council chose to update the catch limits and approved the framework action at its January 2022 meeting.

Management Measures Contained in This Proposed Rule

If implemented, this proposed rule would revise the ACL for the Gulf vermilion snapper stock. The current stock ACL for Gulf vermilion snapper is 3.11 million lb (1.41 million kg), is equal to the ABC, and is based on the results of SEDAR 45, which used data from MRIP–CHTS. This proposed rule would increase the total ACL for Gulf vermilion snapper from 3.11 million lb (1.41 million kg) to 5,452,500 lb (2,473,212 kg). The proposed ACL is based on SEDAR 67, which used MRIP–FES recreational landing estimates and is equal to 75 percent of the ABC as recommended by the Council's AP.

Classification

Pursuant to section 304(b)(1)(A) of the Magnuson-Stevens Act, the NMFS Assistant Administrator has determined that this proposed rule is consistent with the framework action, the FMP, other provisions of the Magnuson-Stevens Act, and other applicable law, subject to further consideration after public comment.

This proposed rule has been determined to be not significant for purposes of Executive Order 12866.

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 proposed rule, if adopted, would not have a significant economic impact on a substantial number of small entities. The factual basis for this determination follows.

A description of this proposed rule, why it is being considered, and the objectives of this proposed rule are contained in the preamble. The Magnuson-Stevens Act provides the statutory basis for this proposed rule.

This proposed rule, if implemented, would apply to all federally-permitted commercial vessels, federally-permitted charter vessels and headboats (for-hire vessels), and recreational anglers that fish for or harvest vermilion snapper in Federal waters of the Gulf. Although the rule and the framework action would apply to for-hire vessels, it would not be expected to have any direct effects on these entities. For-hire vessels sell fishing services to recreational anglers. The proposed changes to the vermilion snapper management measures would not directly alter the services sold by these vessels. Any change in demand for these fishing services, and associated economic effects, as a result of this proposed rule would be a consequence of a change in anglers' behavior, secondary to any direct effect on anglers and, therefore, an indirect effect of the proposed rule. Because the effects on for-hire vessels would be indirect, they fall outside the scope of the RFA. For-hire captains and crew are permitted to retain vermilion snapper under the recreational bag limit; however, they are not permitted to sell these fish. As such, for-hire captains and crew are only affected as recreational anglers. The RFA does not consider recreational anglers to be small entities, so they are also outside the scope of this analysis (5 U.S.C. 603). Small entities include small businesses, small organizations, and small governmental jurisdictions (5 U.S.C. 601(6) and 601(3)–(5)). Recreational anglers are not businesses, organizations, or governmental jurisdictions. In summary, only the impacts on commercial vessels will be discussed.

As of December 21, 2021, there were 747 valid or renewable limited access commercial reef fish permits. A renewable permit is an expired limited access permit that cannot be actively fished, but can be renewed for up to 1 year after expiration. On average from 2015 through 2019, there were 369 federally-permitted commercial vessels each year with reported landings of vermilion snapper in the Gulf. Their average annual vessel-level gross revenue from all species for 2015 through 2019 was approximately $156,000 (2020 dollars) and vermilion snapper accounted for approximately 7 percent of this revenue. For vessels that harvest reef fish species in the Gulf, NMFS estimates that economic profits are equivalent to 34 percent of annual gross revenue, on average. The maximum annual revenue from all species reported by a single one of the commercial vessels that landed Gulf vermilion snapper from 2015 through 2019 was approximately $2.4 million (2020 dollars).

For RFA purposes only, the NMFS has established a small business size standard for businesses, including their affiliates, whose primary industry is commercial fishing (see 50 CFR 200.2). A business primarily engaged in commercial fishing (NAICS code 11411) is classified as a small business if it is independently owned and operated, is not dominant in its field of operation (including its affiliates), and has combined annual receipts not in excess of $11 million for all its affiliated operations worldwide. All of the commercial fishing businesses directly regulated by this proposed rule are believed to be small entities based on the NMFS size standard. No other small entities that would be directly affected by this proposed rule have been identified.

This proposed rule would modify the Gulf vermilion snapper stock ACL based on the recommendation of the Gulf Council's SSC and AP. The ACL would be set at 75 percent of the ABC or 5,452,500 lb (2,473,212 kg). This value is not directly comparable to the current ACL of 3,110,000 lb (1,410,000 kg) because the current ACL is based on MRIP–CHTS data for the recreational sector; whereas, the proposed ACL is based on newer MRIP–FES data. It is not possible to distinguish the portion of the increase to the vermilion snapper ACL due to the conversion from MRIP–CHTS to MRIP–FES units from the portion attributable to improvements in the health of the vermilion snapper stock. Therefore, economic effects that would be expected to result from this proposed action cannot be quantified. Relative to the status quo, an increased stock ACL for vermilion snapper would be expected to afford additional fishing opportunities to the commercial sector, thereby potentially increasing ex-vessel revenue and profits. Such effects would only materialize if the commercial sector is able to increase landings relative to status quo landings.

In summary, the information provided above supports a determination that this proposed rule would not have a significant economic impact on a substantial number of small entities. As a result, an initial regulatory flexibility analysis is not required and none has been prepared.

No duplicative, overlapping, or conflicting Federal rules have been identified. In addition, no new reporting, record-keeping, or other compliance requirements are introduced by this proposed rule.

This proposed rule contains no information collection requirements under the Paperwork Reduction Act of 1995.

List of Subjects in 50 CFR Part 622

Annual catch limits, Fisheries, Fishing, Gulf, Reef fish, Vermilion snapper.

Dated: December 1, 2022.

Samuel D. Rauch, III,

Deputy Assistant Administrator for Regulatory Programs, National Marine Fisheries Service.

For the reasons set out in the preamble, NMFS proposes to amend 50 CFR part 622 as follows:

PART 622—FISHERIES OF THE CARIBBEAN, GULF OF MEXICO, AND SOUTH ATLANTIC

■ 1. The authority citation for part 622 continues to read as follows:

Authority: 16 U.S.C. 1801 *et seq.*

■ 2. In § 622.41, revise the last sentence of paragraph (j) to read as follows:

§ 622.41 Annual catch limits (ACLs), annual catch targets (ACTs), and accountability measures (AMs).

* * * * *

(j) * * * The stock ACL for vermilion snapper is 5,452,500 lb (2,473,212 kg), round weight.

* * * * *

[FR Doc. 2022–26484 Filed 12–5–22; 8:45 am]

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 648

[Docket No. 221129–0253]

RIN 0648–BL83

Fisheries of the Northeastern United States; 2023 Summer Flounder, Scup, and Black Sea Bass Specifications

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

ACTION: Proposed rule; request for comments.

SUMMARY: NMFS proposes 2023 specifications for the summer flounder, scup, and black sea fisheries. The implementing regulations for the Summer Flounder, Scup, and Black Sea Bass Fishery Management Plan require us to publish specifications for the upcoming fishing year for each of these species and to provide an opportunity for public comment. The proposed specifications are intended to establish allowable harvest levels for these species that will prevent overfishing, consistent with the most recent scientific information. This rule also proposes to make a change to the regulations to facilitate states' participation in a Wave 1 (January–February) recreational black sea bass fishery.

DATES: Comments must be received on or before December 21, 2022.

ADDRESSES: You may submit comments on this document, identified by NOAA–NMFS–2022–0112, by any of the following methods:

- *Electronic Submission:* Submit all electronic public comments via the Federal e-Rulemaking Portal. Go to *https://www.regulations.gov* and enter NOAA–NMFS–2022–0112 in the Search box. Click on the ''Comment'' icon, complete the required fields, and enter or attach your comments.

Instructions: Comments sent by any other method, to any other address or individual, or received after the end of the comment period, may not be considered by NMFS. All comments received are a part of the public record and will generally be posted for public viewing on *www.regulations.gov* without change. All personal identifying information (*e.g.,* name, address, etc.), confidential business information, or otherwise sensitive information submitted voluntarily by the sender will be publicly accessible. NMFS will accept anonymous comments (enter ''N/A'' in the required fields if you wish to remain anonymous).

A Supplemental Information Report (SIR) was prepared for the 2023 summer flounder, scup, and black sea bass specifications and a Categorical Exclusion (CE) was prepared for the administrative change for the Wave 1 black sea bass fishery. Copies of the SIR and CE are available upon request from Dr. Christopher M. Moore, Executive Director, Mid-Atlantic Fishery Management Council, Suite 201, 800 North State Street, Dover, DE 19901.

FOR FURTHER INFORMATION CONTACT: Laura Hansen, Fishery Management Specialist, (978) 281–9225.

SUPPLEMENTARY INFORMATION:

General Background

The Mid-Atlantic Fishery Management Council and the Atlantic States Marine Fisheries Commission cooperatively manage the summer flounder, scup, and black sea bass fisheries. The Summer Flounder, Scup, and Black Sea Bass Fishery Management Plan (FMP) outlines the Council's process for establishing specifications. The FMP requires NMFS to set an acceptable biological catch (ABC), annual catch limit (ACL), annual catch targets (ACT), commercial quotas, recreational harvest limits (RHL), and other management measures, for 1 to 3 years at a time. In December 2021, the Council and Board adopted revised quota allocations for these three species to the commercial and recreational sectors of the fisheries as part of the Commercial-Recreational Allocation Amendment (Amendment 22). NMFS approved Amendment 22 on November 7, 2022. This action would set the ABC, as well as the recreational and commercial ACL, ACT, commercial quotas, and RHL for all three species, for 2023, consistent with the recommendations made by the Commission's Summer Flounder, Scup, and Black Sea Bass Board and Council at their joint August 2022 meeting. This rule also proposes to make a change to the regulations to facilitate states' participation in a Wave 1 recreational black sea bass fishery.

Proposed 2023 Specifications

Proposed specifications for summer flounder, scup, and black sea bass are outlined in Table 1.

TABLE 1—PROPOSED 2023 SUMMER FLOUNDER, SCUP, AND BLACK SEA BASS SPECIFICATIONS

(Million lb/metric tons (mt))

	Summer flounder	Scup	Black sea bass
Overfishing Limit (OFL)	34.98 lb (15,867 mt)	30.09 lb (13,649 mt)	17.01 lb (7,716 mt)
Acceptable Biological Catch (ABC)	33.12 lb (15,023 mt)	29.67 lb (13,458 mt)	16.66 lb (7,557 mt)
Commercial ACL = Commercial Annual Catch Target (ACT)	18.21 lb (8,260 mt)	19.29 lb (8,750 mt)	7.50 lb (3,402 mt)
Commercial Quota	15.27 lb (6,926 mt)	14.01 lb (6,355 mt)	4.80 lb (2,177 mt)
Recreational ACL = Recreational ACT	14.90 lb (6,759 mt)	10.39 lb (4,713 mt)	9.16 lb (4,155 mt)
Recreational Harvest Limit	10.62 lb (4,817 mt)	9.27 lb (4,205 mt)	6.57 lb (2,980 mt)

Summer Flounder

The Council and Board approved a revised summer flounder commercial quota of 15.27 million lb (6,926 mt) and a revised RHL of 10.62 million lb (4,817 mt) for 2023. These specifications reflect the summer flounder allocations resulting from Amendment 22, which allocates 55 percent of the ABC to the commercial sector and 45 percent to the recreational sector beginning in 2023.

This action also sets the initial and recently modified summer flounder state-by-state quotas. NMFS will announce any adjustments needed to account for any previous overages in the final rule, prior to the start of the 2023 fishing year.

TABLE 2—INITIAL 2023 SUMMER FLOUNDER STATE-BY-STATE QUOTAS

State	Initial quota (lb)	Initial quota (mt)
ME	23,598	11
NH	19,100	9
MA	1,358,834	616
RI	2,205,205	1,000
CT	923,031	419
NY	1,437,768	652
NJ	2,304,717	1,045
DE	20,755	9
MD	902,214	409
VA	2,743,231	1,244
NC	3,328,558	1,510
Total	1,5267,012	6,925

This action makes no changes to the current commercial management measures, including the minimum fish size (14-inch (36-cm) total length), gear requirements, and possession limits. Recreational management measures for 2023 will be decided on and finalized later this year through a separate rulemaking.

Scup

The Council and Board approved a revised scup commercial quota of 14.01 million lb (6,355 mt) and a revised RHL of 9.27 million lb (4,205 mt) for 2023 (Table 1). These revisions reflect the scup allocations resulting from Amendment 22, which allocates 65 percent of the ABC to the commercial sector and 35 percent to the recreational sector beginning in 2023.

The commercial scup quota is divided into three commercial fishery quota periods, as outlined in Table 3.

TABLE 3—COMMERCIAL SCUP QUOTA ALLOCATIONS FOR 2023 BY QUOTA PERIOD

Quota period	Percent share	lb	mt
Winter I	45.11	6,319,911	2,867
Summer	38.95	5,456,895	2,475
Winter II	15.94	2,233,194	1,013
Total	100	14,010,000	6,355

The current quota period possession limits are not changed by this action, and are outlined in Table 4.

TABLE 4—COMMERCIAL SCUP POSSESSION LIMITS BY QUOTA PERIOD

Quota period	Percent share	Federal possession limits (per trip)	
		lb	kg
Winter I	45.11	50,000	22,680
Summer	38.95	N/A	N/A
Winter II	15.94	12,000	5,443
Total	100.0	N/A	N/A

The Winter I possession limit will drop to 1,000 lb (454 kg) when 80 percent of that period's allocation is landed. If the Winter I quota is not fully harvested, the remaining quota is transferred to Winter II. The Winter II possession limit may be adjusted (in association with a transfer of unused Winter I quota to the Winter II period) via notice in the **Federal Register**. The regulations at 50 CFR 648.122(d) specify that the Winter II possession limit increases consistent with the increase in the quota, as described in Table 5.

TABLE 5—POTENTIAL INCREASE IN WINTER II POSSESSION LIMITS BASED ON THE AMOUNT OF UNUSED SCUP ROLLED OVER FROM WINTER I TO WINTER II

Initial winter II possession limit		Rollover from winter I to winter II		Increase in initial winter II possession limit		Final winter II possession limit after rollover from winter I to winter II	
lb	kg	lb	kg	lb	kg	lb	kg
12,000	5,443	0–499,999	0–226,796	0	0	12,000	5,443
12,000	5,443	500,000–999,999	226,796–453,592	1,500	680	13,500	6,123
12,000	5,443	1,000,000–1,499,999	453,592–680,388	3,000	1,361	15,000	6,804
12,000	5,443	1,500,000–1,999,999	680,389–907,184	4,500	2,041	16,500	7,484
12,000	5,443	2,000,000–2,500,000*	907,185–1,133,981	6,000	2,722	18,000	8,165

* This process of increasing the possession limit in 1,500 lb (680 kg) increments would continue past 2,500,000 lb (1,122,981 kg), but we end here for the purpose of this example.

This action proposes no changes to the 2023 commercial management measures for scup, including the minimum fish size (9-inch (22.9-cm) total length), gear requirements, and quota period possession limits. As with summer flounder and black sea bass, potential changes to the recreational measures (bag limits, size limits, and seasons) for 2023 will be considered later this year.

Black Sea Bass

The Council and Board approved a revised black sea bass commercial quota of 4.80 million lb (2,177 mt) and a revised RHL of 6.57 million lb (2,980 mt) for 2023. As with the other species, these specifications reflect the black sea bass allocations resulting from Amendment 22, which allocates 45 percent of the ABC to the commercial sector and 55 percent to the recreational sector beginning in 2023. The revised RHL also incorporates a change in the recreational discards projection method. The Council and Board considered input from the Monitoring Committee on two potential methods for projecting recreational dead discards and, ultimately, agreed to use an average of the two approaches (2.59 million lb (1,175 mt)). The first method would set projected 2023 recreational dead discards to the most recent three-year average (*i.e.,* 3.04 million lb (1,379 mt)). The second method is the same used to project recreational discards for 2021 and 2022 and this method relies on a proportional average of 2.14 million lb (989 mt). The first method does not rely on an assumption that catch will be equal to the ACL and results in a higher estimate than the second method. The Council and Board agreed that it is very challenging to predict future dead discards, especially given that recent dead discards are not currently available by weight, but by numbers of fish. To generate discard estimates, an ad hoc approach was used that applies the mean weight of a discarded fish from 2019 to the number of dead discards. The 2020 and 2021 estimated discards were 3,476,690 lb (1,577 mt) and 4,195,397 lb (1,903 mt) respectively. The Council and Board also agreed that discards in 2023 could fall between the estimates generated by the two approaches; therefore, they decided to use an average of these two approaches. While the average approach appears reasonable, given the uncertainty in estimating discards and because this average approach is different than previously used or considered, we are specifically seeking comment on the merits of and the rationale for the average approach. The proposed 2023 black sea bass specifications are outlined in Table 6.

TABLE 6—PROPOSED BLACK SEA BASS SPECIFICATIONS

Proposed 2023 specifications	million lb	mt
OFL	17.01	7,716
ABC	16.66	7,557
Commercial ACL=ACT	7.50	3,401
Projected commercial dead discards	2.70	1,224
Commercial quota	4.80	2,177
Recreational ACL=ACT	9.16	4,156
Projected recreational dead discards	2.59	1,175
RHL	6.57	2,981

Black Sea Bass February Wave 1 Fishery

The Council and Board also agreed to modify the process for the optional black sea bass February recreational opening to specify that vessels landing black sea bass in a state with an approved Wave 1 recreational fishery are subject to the state regulations during that Wave 1 fishery. Under the current process, states participating in the optional February opening are required to match the Federal waters measures. The Council and Board made this change to address challenges with the process used to waive Federal waters recreational black sea bass measures starting with 2022.

Classification

Pursuant to section 304(b)(1)(A) of the Magnuson Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act), the NMFS Assistant Administrator has determined that this proposed rule is consistent with the Summer Flounder, Scup, and Black Sea Bass FMP, other provisions of the Magnuson-Stevens Act, and other applicable law, subject to further consideration after public comment.

This proposed rule has been determined to be not significant for purposes of Executive Order 12866.

The Chief Counsel for Regulation of the Department of Commerce certified to the Chief Counsel for Advocacy of the Small Business Administration that this proposed rule, if adopted, would not have a significant economic impact on a substantial number of small entities.

The Mid-Atlantic Fishery Management Council conducted an evaluation of the potential socioeconomic impacts of the proposed measures in conjunction with a SIR. The proposed action would set the 2023 catch and landings limits for summer flounder, scup, and black sea bass based on the recommendations of the SSC, the Council, and Board.

Vessel ownership data [1] were used to identify all individuals who own fishing vessels. Vessels were then grouped according to common owners. The resulting groupings were then treated as entities, or affiliates, for purposes of identifying small and large businesses that may be affected by this action.

Commercial and recreational for-hire affiliates potentially regulated by this action include all those with valid commercial fishery permits for summer flounder, scup and back sea bass and any for-hire affiliates that reported landing summer flounder, scup or black sea bass in any year between 2019–2021. A total of 1,072 affiliates were identified as being potentially regulated by this action, 1,066 (99 percent) of which were identified as small businesses and 6 (1 percent) of which were identified as large businesses, based on their average revenues in 2019–2021.

Of the 1,072 potentially regulated affiliates, 302 reported that the majority of their revenues in 2021 came from for-hire fishing. Some of these affiliates may have also participated in commercial fishing. All 302 of the for-hire affiliates were categorized as small businesses based on their average 2019–2021 revenues. It is not possible to determine what proportion of their revenues came from fishing for an individual species. Nevertheless, given the popularity of summer flounder, scup, and black sea bass as recreational species, revenues generated from these species are likely important for many of these affiliates at certain times of the year.

For-hire revenues are impacted by a variety of factors, including regulations and demand for for-hire trips for summer flounder, scup, black sea bass, and other potential target species; weather; the economy; and other factors. Recreational measures to achieve future

[1] Affiliate data for 2019–2021 were provided by the NMFS NEFSC Social Science Branch. This is the latest affiliate data set available for analysis.

RHLs are not yet known, as they are generally considered late in the year for the upcoming year.

It is difficult to predict how recreational effort and harvest may change in 2023 due to the pending implementation of the Recreational Harvest Control Rule Framework/ Addenda, which utilizes a new method to set recreational measures, called the Percent Change Approach. Under the Percent Change Approach, the RHL will factor into the calculation of how measures may need to change, but is only one piece of a new, multi-step process. Measures will not be tied as closely to the RHL as were previously required. Depending on the appropriate percent change in harvest determined by this process later in 2022, recreational measures in 2023 could be unchanged, restricted, or further liberalized from 2022 measures. If restrictions are implemented, given the popularity of these species in this region, this could result in a decrease in for-hire trips, decreased for-hire revenues, and overall slight to moderate negative impacts to recreational for-hire businesses, depending on the scale of the restrictions. If measures are liberalized, this could result in an increase in for-hire trips, increased for-hire revenues, and moderate positive impacts to recreational for-hire businesses. These impacts would be greater in magnitude for the for-hire businesses that depend more heavily on summer flounder, scup or black sea bass. However, as previously stated, it is not possible to determine the relative importance of these species compared to other species for the potentially regulated for-hire affiliates. The administrative change to facilitate the Wave 1 recreational black sea bass fishery will provide participating states greater flexibility in developing measures to fit the unique needs of their fisheries, rather than the one-size-fits all approach under the current process. This is expected to have slight positive economic impacts in states that participate in this opening. It is not expected to impact states that do not participate in this opening.

This action is not expected to adversely impact revenues for commercial and recreational vessels that fish for summer flounder, scup, and black sea bass. Because this rule will not have a significant economic impact on a substantial number of small entities, an initial regulatory flexibility analysis is not required and none has been prepared.

This proposed rule contains no information collection requirements under the Paperwork Reduction Act of 1995.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: November 30, 2022.

Samuel D. Rauch, III,

Deputy Assistant Administrator for Regulatory Programs, National Marine Fisheries Service.

For the reasons set out in the preamble, 50 CFR part 648 is proposed to be amended as follows:

PART 648—FISHERIES OF THE NORTHEASTERN UNITED STATES

■ 1. The authority citation for part 648 continues to read as follows:

Authority: 16 U.S.C. 1801 *et seq.*

■ 2. In § 648.145, revise paragraph (a) to read as follows:

§ 648.145 Black sea bass possession limit.

(a) During the recreational fishing season specified at § 648.146, no person shall possess more than 5 black sea bass in, or harvested from, the EEZ per trip unless that person is the owner or operator of a fishing vessel issued a black sea bass moratorium permit, or is issued a black sea bass dealer permit, unless otherwise specified in the conservation equivalent measures described in § 648.151. Vessels landing black sea bass in a state with an approved Wave 1 recreational fishery are subject to the state regulations regarding possession limit during that Wave 1 fishery. Persons aboard a commercial vessel that is not eligible for a black sea bass moratorium permit may not retain more than 5 black sea bass during the recreational fishing season specified at § 648.146. The owner, operator, and crew of a charter or party boat issued a black sea bass moratorium permit are subject to the possession limit when carrying passengers for hire or when carrying more than five crew members for a party boat, or more than three crew members for a charter boat. This possession limit may be adjusted pursuant to the procedures in § 648.142. However, possession of black sea bass harvested from state waters above this possession limit is allowed for state-only permitted vessels when transiting Federal waters within the Block Island Sound Transit Area provided they follow the provisions at § 648.150 and abide by state regulations.

* * * * *

■ 3. Revise § 648.146 to read as follows:

§ 648.146 Black sea bass recreational fishing season.

Vessels that are not eligible for a black sea bass moratorium permit under § 648.4(a)(7), and fishermen subject to the possession limit specified in § 648.145(a), may only possess black sea bass from May 15 through October 8, unless otherwise specified in the conservation equivalent measures described in § 648.151 or unless this time period is adjusted pursuant to the procedures in § 648.142. However, possession of black sea bass harvested from state waters outside of this season is allowed for state-only permitted vessels when transiting Federal waters within the Block Island Sound Transit Area provided they follow the provisions at § 648.151 and abide by state regulations. Vessels landing black sea bass in a state with an approved Wave 1 recreational fishery are subject to the state regulations regarding fishing season during that Wave 1 fishery.

■ 4. In § 648.147, revise paragraph (b) to read as follows:

§ 648.147 Black sea bass size requirements.

* * * * *

(b) *Party/Charter permitted vessels and recreational fishery participants.* The minimum fish size for black sea bass is 14 inches (35.56 cm) total length for all vessels that do not qualify for a black sea bass moratorium permit, and for party boats holding a black sea bass moratorium permit, if fishing with passengers for hire or carrying more than five crew members, and for charter boats holding a black sea bass moratorium permit, if fishing with more than three crew members, unless otherwise specified in the conservation equivalent measures as described in § 648.151. However, possession of smaller black sea bass harvested from state waters is allowed for state-only permitted vessels when transiting Federal waters within the Block Island Sound Transit Area provided they follow the provisions at § 648.151 and abide by state regulations. Vessels landing black sea bass in a state with an approved Wave 1 recreational fishery are subject to the state regulations regarding size requirements during that Wave 1 fishery.

* * * * *

[FR Doc. 2022–26438 Filed 12–5–22; 8:45 am]

BILLING CODE 3510–22–P

Notices

Federal Register

Vol. 87, No. 233

Tuesday, December 6, 2022

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF AGRICULTURE

Commodity Credit Corporation

Farm Service Agency

[Docket ID FSA–2022–0017]

Information Collection Request; Application for Payment of Amounts Due Persons Who Have Died, Disappeared, or Have Been Declared Incompetent

AGENCY: Commodity Credit Corporation and Farm Service Agency, USDA.

ACTION: Notice; request for comments.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, the Commodity Credit Corporation (CCC) and the Farm Service Agency (FSA) are requesting comments from all interested individuals and organizations on an extension of a currently approved information collection. CCC and FSA use the information to determine whether representatives or survivors of a producer are entitled to receive payments earned by a producer who dies, disappears, or is declared incompetent before receiving payments or other disbursements.

DATES: We will consider comments that we receive by February 6, 2023.

ADDRESSES: We invite you to submit comments on this notice. In your comments, include date, volume, and page number of this issue of the **Federal Register**. You may submit comments by any of the following methods:

- *Federal eRulemaking Portal:* Go to *http://regulations.gov.* Go to *http://www.regulations.gov* and search for Docket ID FSA–2022–0017. Follow the online instructions for submitting comments.
- *Mail:* Joe Lewis Jr., Agricultural Program Specialist, USDA, FSA STOP 0572, 1400 Independence Avenue SW, Washington, DC 20250–0572.

You may also send comments to the Desk Officer for Agriculture, Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503. Copies of the information collection may be requested by contacting Joe Lewis Jr. at the above address.

FOR FURTHER INFORMATION CONTACT: Joe Lewis Jr, (202) 720–0795.

SUPPLEMENTARY INFORMATION:

Description of Information Collection

Title: Application for Payment of Amounts Due Persons Who Have Died, Disappeared, or Have Been Declared Incompetent.

OMB Number: 0560–0226.

OMB Expiration Date of Approval: 04/30/2023.

Type of Request: Extension.

Abstract: Persons desiring to claim payments earned, but not yet paid to a person who has died, disappeared, or has been declared incompetent must complete form FSA–325, Application for Payment of Amounts Due Persons Who Have Died, Disappeared, or Have Been Declared Incompetent. This information required by form FSA–325 is used by FSA county office employees to document the relationship of heirs, beneficiaries, or others who claim that a payment was earned, but not yet paid to the person who died, disappeared, or who has been declared incompetent, and to determine the share and order of precedence for disbursing payments to such persons.

Information is obtained only when a person claims that they are due a payment that was earned, but not paid to a producer that has died, disappeared, or has been declared incompetent, and documentation is needed to determine if any individuals are entitled to receive such payments or disbursements. The burden hours have not changed since the last OMB approval.

For the following estimated total annual burden on respondents, the formula used to calculate the total burden hour is the estimated average time per responses multiplied by the estimated total annual responses.

Estimate of Annual Burden: Public reporting burden for this collection of information is estimated to average 0.50 hours per response.

Type of Respondents: Producers.

Estimated Number of Respondents: 2,000.

Estimated Annual Number of Responses per Respondent: 1.

Estimated Total Annual of Responses: 2,000.

Estimated Average Time per Responses: 0.50 hours.

Estimated Total Annual Burden on Respondents: 1,000.

We are requesting comments on all aspects of this information collection to help us to:

(1) Evaluate whether the collection of information is necessary for the proper performance of the functions of FSA, including whether the information will have practical utility;

(2) Evaluate the accuracy of FSA's estimate of burden including the validity of the methodology and assumptions used;

(3) Enhance the quality, utility, and clarity of the information to be collected;

(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.

All responses to this notice, including names and addresses when provided, will be summarized and included in the request for OMB approval. All comments will also become a matter of public record.

Zach Ducheneaux,

Administrator, Farm Service Agency, and Executive Vice President, Commodity Credit Corporation.

[FR Doc. 2022–26446 Filed 12–5–22; 8:45 am]

BILLING CODE 3411–EZ–P

DEPARTMENT OF AGRICULTURE

Forest Service

Newspapers Used for Publication of Legal Notices by the Intermountain Region, Utah, Idaho, Nevada, and Wyoming

AGENCY: Forest Service, Agriculture (USDA).

ACTION: Notice of newspapers of record.

SUMMARY: This notice lists the newspapers that will be used by the ranger districts, national forests and regional office of the Intermountain Region to publish legal notices required under Title 36 of the Code of Federal Regulations (CFR). The intended effect of this action is to inform interested

members of the public which newspapers the Forest Service will use to publish notices of proposed actions and notices of decision. This will provide the public with constructive notice of Forest Service proposals and decisions provide information on the procedures to comment, object or appeal, and establish the date that the Forest Service will use to determine if comments or appeals/objection were timely.

DATES: The list of newspapers will remain in effect for one year from the date of publication, when another notice will be published in the **Federal Register**.

ADDRESSES: Judd Sampson, Regional Objections Coordinator, Intermountain Region, 324 25th Street, Ogden, UT 84401.

FOR FURTHER INFORMATION CONTACT: Judd Sampson, Regional Objections Coordinator, Intermountain Region, by telephone at 602–525–1914 or by email at *judd.sampson@usda.gov.*

SUPPLEMENTARY INFORMATION: The administrative procedures at 36 CFR 214, 218, and 219 require the Forest Service to publish notices in a newspaper of general circulation. The content of the notices is specified in 36 CFR 214, 218 and 219.

In general, the notices will identify: the decision or project, by title or subject matter; the name and title of the official making the decision; how to obtain additional information; and where and how to file comments or appeals/objection. The date the notice is published will be used to establish the official date for the beginning of the comment or appeal/objection period. The newspapers to be used are as follows:

Regional Forester, Intermountain Region

Regional Forester decisions affecting National Forests in Idaho: Idaho Statesman
Regional Forester decisions affecting National Forests in Nevada: Reno Gazette-Journal
Regional Forester decisions affecting National Forests in Wyoming: Casper Star-Tribune
Regional Forester decisions affecting National Forests in Utah: Salt Lake Tribune
Regional Forester decisions that affect all National Forests in the Intermountain Region: Salt Lake Tribune

Ashley National Forest

Ashley Forest Supervisor decisions: Vernal Express
District Ranger decisions for Duchesne, Roosevelt: Uintah Basin Standard
Flaming Gorge District Ranger for decisions affecting Wyoming: Rocket Miner
Flaming Gorge and Vernal District Ranger for decisions affecting Utah: Vernal Express

Boise National Forest

Boise Forest Supervisor decisions: Idaho Statesman
Cascade District Ranger decisions: The Star-News
Emmett District Ranger decisions: Messenger-Index
District Ranger decisions for Idaho City and Mountain Home Districts: Idaho Statesman
Lowman District Ranger decisions: The Idaho World

Bridger-Teton National Forest

Bridger-Teton Forest Supervisor and District Ranger decisions: Casper Star-Tribune

Caribou-Targhee National Forest

Caribou-Targhee Forest Supervisor decisions for the Caribou portion: Idaho State Journal
Caribou-Targhee Forest Supervisor decisions for the Targhee portion: Post Register
District Ranger decisions for Ashton, Dubois, Island Park, Palisades and Teton Basin: Post Register
District Ranger decisions for Montpelier, Soda Springs and Westside: Idaho State Journal

Dixie National Forest

Dixie Forest Supervisor decisions: The Spectrum
District Ranger decisions for Cedar City and Pine Valley: The Spectrum
District Ranger decisions for Escalante and Powell: The Insider
Decisions affecting the former Teasdale RD area of the Dixie NF; now managed by the Fishlake NF Fremont River District Ranger: The Richfield Reaper

Fishlake National Forest

Fishlake Forest Supervisor and District Ranger decisions: The Richfield Reaper

Humboldt-Toiyabe National Forest

Humboldt-Toiyabe Forest Supervisor decisions that encompass all or portions of both the Humboldt and Toiyabe National Forests: Reno Gazette-Journal
Humboldt-Toiyabe Forest Supervisor decisions for the Humboldt portion: Elko Daily Free Press
Humboldt-Toiyabe Forest Supervisor decisions for the Toiyabe portion: Reno Gazette-Journal
Austin-Tonopah District Ranger decisions: Reno Gazette-Journal
Bridgeport District Ranger decisions: Reno Gazette-Journal
Carson District Ranger decisions: Reno Gazette-Journal
Ely District Ranger decisions: The Ely Times
Mountain City, Ruby Mountains and Jarbidge District Ranger decisions: Elko Daily Free Press
Santa Rosa District Ranger decisions: Humboldt Sun
Spring Mountains National Recreation Area District Ranger decisions: Las Vegas Review Journal

Manti-La Sal National Forest

Manti-La Sal Forest Supervisor decisions: ETV News Sun Advocate (Emery Telcom)
Ferron District Ranger decisions: ETV News Progress (Emery Telcom)
Moab District Ranger decisions: The Times-Independent
Monticello District Ranger decisions: San Juan Record
Price District Ranger decisions: ETV News Sun Advocate (Emery Telcom)
Sanpete District Ranger decisions: Sanpete Messenger

Payette National Forest

Payette Forest Supervisor decisions: Idaho Statesman
Council District Ranger decisions: Adams County Record
District Ranger decisions for Krassel, McCall and New Meadows: The Star News
Weiser District Ranger decisions: Signal American

Salmon-Challis National Forest

Salmon-Challis Forest Supervisor decisions for the Salmon portion: The Recorder-Herald
Salmon-Challis Forest Supervisor decisions for the Challis portion: The Challis Messenger
District Ranger decisions for Lost River, Middle Fork and Challis-Yankee Fork: The Challis Messenger
District Ranger decisions for Leadore, North Fork and Salmon-Cobalt: The Recorder-Herald

Sawtooth National Forest

Sawtooth Forest Supervisor decisions: Times-News
District Ranger decisions for Fairfield and Minidoka: Times-News
Ketchum District Ranger decisions: Idaho Mountain Express
Sawtooth National Recreation Area: The Challis Messenger

Uinta-Wasatch-Cache National Forest

Forest Supervisor decisions for the Uinta portion, including the Vernon Unit: Provo Daily Herald
Forest Supervisor decisions for the Wasatch-Cache portion: Salt Lake Tribune
Forest Supervisor decisions for the entire Uinta-Wasatch-Cache: Salt Lake Tribune
District Ranger decisions for the Heber-Kamas, Pleasant Grove and Spanish Fork Ranger Districts: Provo Daily Herald
District Ranger decisions for Evanston and Mountain View: Uinta County Herald
District Ranger decisions for Salt Lake: Salt Lake Tribune
District Ranger decisions for Logan: Logan Herald Journal
District Ranger decisions for Ogden: Standard Examiner

Dated: November 22, 2022.

Troy Heithecker,

Associate Deputy Chief, National Forest System.

[FR Doc. 2022–26481 Filed 12–5–22; 8:45 am]

BILLING CODE 3411–15–P

DEPARTMENT OF COMMERCE

International Trade Administration

[C–580–888]

Certain Carbon and Alloy Steel Cut-to-Length Plate From the Republic of Korea: Final Results of Countervailing Duty Administrative Review; 2020

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce

SUMMARY: The U.S. Department of Commerce (Commerce) determines that POSCO, a producer/exporter of certain carbon and alloy steel cut-to-length plate (CTL plate) from the Republic of Korea (Korea), received *de minimis* net countervailable subsidies during the period of review (POR), January 1, 2020, through December 31, 2020.

DATES: Applicable December 6, 2022.

FOR FURTHER INFORMATION CONTACT: Faris Montgomery, AD/CVD Operations, Office VIII, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–1537.

SUPPLEMENTARY INFORMATION:

Background

On June 3, 2022, Commerce published the *Preliminary Results* of this administrative review in the **Federal Register**.[1] On August 15, 2022, Commerce extended the deadline for the final results of this review to no later than November 30, 2022.[2] For a complete description of the events that followed the *Preliminary Results, see* the Issues and Decision Memorandum.[3]

We conducted this review in accordance with section 751 of the Tariff Act of 1930, as amended (the Act).

Scope of the Order[4]

The merchandise covered by the *Order* is CTL plate. For a complete description of the scope of the *Order, see* the Issues and Decision Memorandum.

Analysis of Comments Received

All issues raised in interested parties' briefs are addressed in the Issues and Decision Memorandum. A list of the issues addressed is attached to this notice at the 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.*

Verification

As provided in section 782(i) of the Act, in September 2022, Commerce conducted an on-site verification of the subsidy information reported by POSCO. We used standard on-site verification procedures, including an examination of relevant accounting records and original source documents provided by the respondent.

Changes Since the Preliminary Results

Based on our analysis of the case and rebuttal briefs and the evidence on the record, we made certain changes to POSCO's countervailable subsidy calculations from the *Preliminary Results.* These changes are explained in the Issues and Decision Memorandum.

Final Results of Administrative Review

In accordance with 19 CFR 351.221(b)(4)(i), we calculated an individual net countervailable subsidy rate for POSCO. Commerce determines that, during the POR, the net countervailable subsidy rate for the producers/exporter under review is as follows:

Producer/exporter	Subsidy rate (percent *ad valorem*)
POSCO[5]	0.33 (*de minimis*).

Disclosure

Commerce intends to disclose the calculations performed for these final results of review within five days of the date of publication of this notice in the **Federal Register**.[6]

Assessment Rates

Pursuant to 19 CFR 351.212(b)(2), Commerce will determine, and U.S. Customs and Border Protection (CBP) shall assess, countervailing duties on all appropriate entries of subject merchandise in accordance with the final results of this review, for the above-listed company at the applicable *ad valorem* assessment rate. We intend to issue assessment instructions to CBP no earlier than 35 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

[1] *See Certain Carbon and Alloy Steel Cut-to-Length Plate from the Republic of Korea: Preliminary Results of Countervailing Duty Administrative Review, and Intent to Rescind Review, in Part; 2020,* 87 FR 33720 (June 3, 2022) (*Preliminary Results*).

[2] *See* Memorandum, ''Extension of Deadline for Final Results of Countervailing Duty Administrative Review,'' dated August 15, 2022.

[3] *See* Memorandum, ''Issues and Decision Memorandum for the Final Results of the Countervailing Duty Administrative Review: Certain Carbon and Alloy Steel Cut-to-Length Plate from the Republic of Korea; 2020,'' dated concurrently with, and hereby adopted by, this notice (Issues and Decision Memorandum).

[4] *See Certain Carbon and Alloy Steel Cut-to-Length Plate from the Republic of Korea: Countervailing Duty Order,* 82 FR 24103 (May 25, 2017) (*Order*).

[5] As discussed in the *Preliminary Results,* Commerce found the following companies to be cross-owned with POSCO: Pohang Scrap Recycling Distribution Center Co., Ltd.; POSCO Chemical Co., Ltd.; POSCO M-Tech Co., Ltd.; POSCO Nippon Steel RHF Joint Venture Co., Ltd.; POSCO SPS Co., Ltd.; and POSCO Terminal Co., Ltd. The subsidy rate applies to all cross-owned companies. We noted that POSCO has an affiliated trading company through which it exported certain subject merchandise during the POR, POSO International (aka POSCO International Corporation). POSCO International was not selected as a mandatory respondent but was examined in the context of POSCO. Therefore, there is not an established countervailing duty rate for POSCO International; POSCO International's subsidies are accounted for in POSCO's total subsidy rate. Instead, entries of subject merchandise exported by POSCO International will receive the rate of the producer listed on the U.S. Customs and Border Protection (CBP) entry form. Thus, the subsidy rate applied to POSCO and POSCO's cross-owned companies is also applied to POSCO International for entries of subject merchandise produced by POSCO.

[6] *See* 19 CFR 351.224(b).

time for parties to file a request for a statutory injunction has expired (*i.e.,* within 90 days of publication).

Cash Deposit Instructions

In accordance with section 751(a)(1) of the Act, Commerce intends to instruct CBP to collect cash deposits of estimated countervailing duties in the amounts shown for the company listed above based on shipments of subject merchandise entered, or withdrawn from warehouse, for consumption on or after the date of publication of the final results of this administrative review.[7] For all non-reviewed firms subject to the *Order,* we will instruct CBP to continue to collect cash deposits of estimated countervailing duties at the most recent company-specific rate or the all-others rate (3.72 percent), as appropriate.[8] These cash deposit requirements, effective upon publication of these final results, shall remain in effect until further notice.

Administrative Protective Order

This notice also serves as a reminder to parties subject to an administrative protective order (APO) of their responsibility concerning the destruction of proprietary information disclosed under APO in accordance with 19 CFR 351.305(a)(3). Timely written notification of the return or destruction of APO materials or conversion to judicial protective order is hereby requested. Failure to comply with the regulations and terms of an APO is a sanctionable violation.

Notification to Interested Parties

We are issuing and publishing these final results in accordance with sections 751(a)(1) and 777(i) of the Act.

Dated: November 30, 2022.

Lisa W. Wang,

Assistant Secretary for Enforcement and Compliance.

Appendix

List of Topics Discussed in the Issues and Decision Memorandum

I. Summary
II. Background
III. Scope of the *Order*
IV. Subsidies Valuation Information
V. Analysis of Programs
VI. Discussion of Comments
Comment 1: Whether Electricity Is Subsidized by the Government of Korea (GOK)
Comment 2: Whether Commerce Is Required by Law to Conduct Verification of the GOK's Questionnaire Responses
Comment 3: Whether the Provision of Korea Emissions Trading System (K–ETS) Permits Is Countervailable
a. Whether the Provision of K–ETS Permits Provides a Financial Contribution and Benefit
b. Whether the Provision of K–ETS Permits Is Specific
Comment 4: Whether Commerce Should Correct Errors in its Calculation of the Benefit under the Provision of K–ETS Permits
Comment 5: Whether Local Tax Exemptions under RSLTA Article 57–2 Are Countervailable
Comment 6: Whether Certain of POSCO Chemical Co., Ltd.'s (POSCO Chemical) Local Tax Exemptions under Restriction of Special Local Taxation Act (RSLTA) Article 78 Are Tied to Non-Subject Merchandise
Comment 7: Whether Certain Quota Tariff Import Duty Exemptions under Article 71 of the Customs Act Are Tied to Non-Subject Merchandise
VII. Recommendation

[7] *See, e.g., Honey from Argentina: Results of Countervailing Duty Administrative Review,* 69 FR 29518 (May 24, 2004), and accompanying Issues and Decision Memorandum at Issue 4.

[8] *See Order,* 82 FR at 24103.

[FR Doc. 2022–26460 Filed 12–5–22; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–533–823]

Silicomanganese From India: Final Results of Antidumping Duty Changed Circumstances Review

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: On October 21, 2022, the U.S. Department of Commerce (Commerce) published the notice of initiation and preliminary results of changed circumstances reviews (CCR) of the antidumping duty (AD) order on silicomanganese from India. For these final results, Commerce continues to find that NAVA Limited (NAVA) is the successor-in-interest to Nava Bharat Ventures Limited (NBVL) in the context of the AD order on silicomanganese from India. Furthermore, NAVA is entitled to NBVL's AD cash deposit rate with respect to entries of subject merchandise in the above-referenced proceeding.

DATES: Applicable December 6, 2022.

FOR FURTHER INFORMATION CONTACT: Daniel Alexander, AD/CVD Operations, Office VII, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–4313.

SUPPLEMENTARY INFORMATION:

Background

On October 21, 2022, Commerce published the *Initiation and Preliminary Results,* finding that NAVA is the successor-in-interest to NBVL, and that it should be assigned the same AD cash deposit rate assigned to NBVL in the above-referenced proceeding.[1] In the *Initiation and Preliminary Results,* interested parties were provided an opportunity to comment regarding our preliminary findings. Commerce received no comments from interested parties.

Scope of the Order [2]

The merchandise covered by the *Order* is all forms, sizes, and compositions of silicomanganese, except low-carbon silicomanganese, including silicomanganese briquettes, fines and slag. For a full description of the scope of the *Order, see* the *Initiation and Preliminary Results.*

Final Results of Changed Circumstances Review

For the reasons stated in the *Initiation and Preliminary Results,* and because we received no comments from interested parties to the contrary, Commerce continues to find that NAVA is the successor-in-interest to NBVL for AD purposes. As a result of this determination, NAVA is entitled to the same AD cash deposit rate as NBVL with respect to entries of subject merchandise in the above-noted proceeding.[3]

Commerce will instruct U.S. Customs and Border Protection to suspend liquidation of all shipments of subject merchandise produced and/or exported by NAVA and entered, or withdrawn from warehouse, for consumption on or after the publication date of this notice in the **Federal Register** at the current AD cash deposit rate on silicomanganese in effect for NBVL. These cash deposit requirements shall remain in effect until further notice.

Notification to Interested Parties

This notice is published in accordance with sections 751(b)(1) and 777(i)(1) and (2) of the Tariff Act of 1930, as amended, and 19 CFR

[1] *See Silicomanganese from India: Notice of Initiation and Preliminary Results of Changed Circumstances Review,* 87 FR 64006 (October 21, 2022) (*Initiation and Preliminary Results*), and accompanying Preliminary Decision Memorandum.

[2] *See Notice of Amended Final Determination of Sales at Less than Fair Value and Antidumping Duty Orders: Silicomanganese from India, Kazakhstan, and Venezuela,* 67 FR 36149 (May 23, 2002) (*Order*).

[3] In accordance with this **Federal Register** notice, NAVA will receive the AD cash deposit rate assigned to NBVL under the *Order.*

351.216(e), 351.221(b), and 351.221(c)(3).

Dated: November 28, 2022.

Abdelali Elouaradia,

Deputy Assistant Secretary for Enforcement and Compliance.

[FR Doc. 2022–26448 Filed 12–5–22; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–560–826]

Monosodium Glutamate From the Republic of Indonesia: Preliminary Results of Antidumping Duty Administrative Review; 2020–2021

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The U.S. Department of Commerce (Commerce) preliminarily determines that sales of monosodium glutamate (MSG) from the Republic of Indonesia (Indonesia) have been made below normal value during the period of review (POR), November 1, 2020, through October 31, 2021. We invite interested parties to comment on these preliminary results.

DATES: Applicable December 6, 2022.

FOR FURTHER INFORMATION CONTACT: Andrew Huston, AD/CVD Operations, Office VII, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–4261.

SUPPLEMENTARY INFORMATION:

Background

Commerce is conducting an administrative review of the antidumping duty order on MSG from Indonesia covering two respondents: PT. Cheil Jedang Indonesia (CJ Indonesia) and PT. Miwon Indonesia (PT. Miwon).[1] For a complete description of the events that followed the initiation of this review, *see* the Preliminary Decision Memorandum.[2] On July 11, 2022, we extended the deadline for these preliminary results until no later than November 30, 2022.[3]

Scope of the Order [4]

The merchandise covered by this *Order* is MSG, whether or not blended or in solution with other products. Specifically, MSG that has been blended or is in solution with other product(s) is included in the *Order* when the resulting mix contains 15 percent or more of MSG by dry weight. Products with which MSG may be blended include, but are not limited to, salts, sugars, starches, maltodextrins, and various seasonings. Further, MSG is included in the *Order* regardless of physical form (including, but not limited to, in monohydrate or anhydrous form, or as substrates, solutions, dry powders of any particle size, or unfinished forms such as MSG slurry), end-use application, or packaging. For a full description of the scope of the *Order, see* the Preliminary Decision Memorandum.

Methodology

Commerce is conducting this review in accordance with section 751(a) of the Tariff Act of 1930, as amended (the Act). Export price and constructed export price are calculated in accordance with section 772 of the Act. Normal value is calculated in accordance with section 773 of the Act. Further, because CJ Indonesia failed to cooperate to the best of its ability in responding to our requests for information, we relied on facts available, with adverse inferences, in determining this company's dumping margin, consistent with section 776 of the Act.

For a full description of the methodology underlying our conclusions, *see* the Preliminary Decision Memorandum. A list of topics included in the Preliminary Decision Memorandum is included as an appendix to this notice. The Preliminary Decision Memorandum 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 Preliminary Decision Memorandum can be accessed directly at *https://access.trade.gov/public/FRNoticesListLayout.aspx.*[5]

Preliminary Results of Review

As a result of our review, we preliminarily determine the following weighted-average dumping margins for the period November 1, 2020, through October 31, 2021:

Manufacturer/exporter	Weighted-average dumping margin (percent)
PT. Cheil Jedang Indonesia	* 58.67
PT. Daesang Ingredients Indonesia and PT. Miwon Indonesia [5]	14.61

* Rate based on adverse facts available.

Disclosure and Public Comment

Commerce intends to disclose the calculations used in our analysis to parties in this review within five days of the date of publication of this notice in accordance with 19 CFR 351.224(b). Interested parties are invited to comment on the preliminary results of this review. Pursuant to 19 CFR 351.309(c)(1)(ii), interested parties may submit case briefs not later than 30 days after the date of publication of this notice. Rebuttal briefs, limited to issues raised in the case briefs, may be filed later than seven days after the date for filing case briefs.[6] Parties who submit case briefs or rebuttal briefs in this review are requested to submit with each brief: (1) a statement of the issue; (2) a brief summary of the argument; and (3) a table of authorities.[7] Case and rebuttal briefs should be filed using ACCESS and must be served on

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[1] *See Initiation of Antidumping and Countervailing Duty Administrative Reviews,* 86 FR 73734 (December 28, 2021). On August 26, 2022, Commerce published the final results of a changed circumstances review of MSG from Indonesia. Commerce found that PT. Daesang Ingredients Indonesia (PT. Daesang) is the successor-in-interest to PT. Miwon. *See Monosodium Glutamate from the Republic of Indonesia: Final Results of Changed Circumstances Review,* 87 FR 52506 (August 26, 2022) (*MSG from Indonesia CCR*). Because the effective date of this decision was after the POR, we continue to reference the respondent here as PT. Miwon.

[2] *See* Memorandum, ''Decision Memorandum for the Preliminary Results of the Antidumping Duty Administrative Review: Monosodium Glutamate from the Republic of Indonesia; 2020–20201'' dated concurrently with, and hereby adopted by, this notice (Preliminary Decision Memorandum).

[3] *See* Memorandum, ''Monosodium Glutamate from Indonesia: Extension of Deadline for Preliminary Results of Review,'' dated July 16, 2021.

[4] *See Monosodium Glutamate from the People's Republic of China, and the Republic of Indonesia: Antidumping Duty Orders; and Monosodium Glutamate from the People's Republic of China: Amended Final Determination of Sales at Less Than Fair Value,* 79 FR 70505 (November 26, 2014) (*Order*).

[5] As noted above, on August 26, 2022, Commerce published the final results of a changed circumstances review of MSG from Indonesia. Commerce found that PT. Daesang is the successor-in-interest to PT. Miwon. *See MSG from Indonesia CCR.* Cash deposits of estimated antidumping duties required pursuant to the final results of this review will be applied to PT. Daesang. Liquidation instructions for the POR will be issued for PT. Miwon.

[6] *See* 19 CFR 351.309(d); *see also Temporary Rule Modifying AD/CVD Service Requirements Due to COVID–19,* 85 FR 17006, 17007 (March 26, 2020) (''To provide adequate time for release of case briefs via ACCESS, E&C intends to schedule the due date for all rebuttal briefs to be 7 days after case briefs are filed (while these modifications remain in effect)'').).

[7] *See* 19 CFR 351.309(c)(2), (d)(2).

interested parties.[8] Note that Commerce has temporarily modified certain of its requirements for serving documents containing business proprietary information, until further notice.[9]

Pursuant to 19 CFR 351.310(c), any interested party may request a hearing within 30 days of the publication of this notice in the **Federal Register**. If a hearing is requested, Commerce will notify interested parties of the hearing schedule. Interested parties who wish to request a hearing, or to participate if one is requested, must submit a written request to the Assistant Secretary for Enforcement and Compliance, filed electronically via ACCESS within 30 days after the date of publication of this notice. Requests should contain: (1) the party's name, address, and telephone number; (2) the number of participants; and (3) a list of the issues to be discussed. Issues raised in the hearing will be limited to those raised in the respective case briefs.

Assessment Rates

Upon completion of the administrative review, Commerce shall determine, and U.S. Customs and Border Protection (CBP) shall assess, antidumping duties on all appropriate entries covered by this review.[10] If the weighted-average dumping margin is not zero or *de minimis* (*i.e.,* less than 0.5 percent), then Commerce will calculate importer-specific *ad valorem* antidumping duty assessment rates based on the ratio of the total amount of dumping calculated for each importer's examined sales to the total entered value of those same sales in accordance with 19 CFR 351.212(b)(1). If the weighted-average dumping margin is zero or *de minimis* in the final results, or if an importer-specific assessment rate is zero or *de minimis* in the final results, Commerce will instruct CBP to liquidate the appropriate entries without regard to antidumping duties.

In accordance with Commerce's ''automatic assessment'' practice, for entries of subject merchandise that entered the United States during the POR that were produced by PT. Miwon for which PT. Miwon did not know that its merchandise was destined to the United States, Commerce will instruct CBP to liquidate unreviewed entries at the all-others rate of 6.19 percent,[11] if there is no rate for the intermediate company(ies) involved in the transaction.[12] The final results of this review shall be the basis for the assessment of antidumping duties on entries of subject merchandise covered by the final results of this review, where applicable.

Commerce intends to issue assessment instructions to CBP no earlier than 35 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 deposit requirements will be effective for all shipments of MSG from Indonesia entered, or withdrawn from warehouse, for consumption on or after the date of publication of the final results of this administrative review, as provided for by section 751(a)(2)(C) of the Act: (1) the cash deposit rate for the companies under review will be the rate established in the final results of this review (except, if the rate is zero or *de minimis,* no cash deposit will be required); (2) for previously reviewed or investigated companies not listed above, the cash deposit rate will continue to be the company-specific rate published for the most recent period; (3) if the exporter is not a firm covered in this review, a prior review, or the less-than-fair-value investigation, but the manufacturer is, the cash deposit rate will be the rate established for the most recent period for the manufacturer of the merchandise; and (4) the cash deposit rate for all other manufacturers or exporters will continue to be 6.19 percent, the all-others rate established in the investigation.[13] These cash deposit requirements, when imposed, shall remain in effect until further notice.

Final Results of Review

Unless otherwise extended, Commerce intends to issue the final results of this administrative review, including the results of our analysis of issues raised by the parties in the written comments, within 120 days of publication of these preliminary results in the **Federal Register**, pursuant to section 751(a)(3)(A) of the Act and 19 CFR 351.213(h)(1).

Notification to Importers

This notice also serves as a preliminary reminder to importers of their responsibility under 19 CFR 351.402(f) 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 Commerce's presumption that reimbursement of antidumping duties occurred and the subsequent assessment of double antidumping duties.

Notification to Interested Parties

These preliminary results of administrative review are issued and published in accordance with sections 751(a)(1) and 777(i)(1) of the Act, and 19 CFR 351.221(b)(4).

Dated: November 30, 2022.

Lisa W. Wang,

Assistant Secretary for Enforcement and Compliance.

Appendix—List of Topics Discussed in the Preliminary Decision

Memorandum

I. Summary
II. Background
III. Scope of the *Order*
IV. Application of Facts Available and Use of Adverse Inferences
V. Discussion of The Methodology
VI. Normal Value
VII. Currency Conversion
VIII. Recommendation

[FR Doc. 2022–26491 Filed 12–5–22; 8:45 am]

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[8] *See* 19 CFR 351.303 (for general filing requirements).

[9] *See* 19 CFR 351.303(f).

[10] *See* 19 CFR 351.212(b).

[11] *See Order.*

[12] For a full discussion of this practice, *see Antidumping and Countervailing Duty Proceedings: Assessment of Antidumping Duties,* 68 FR 23954 (May 6, 2003).

[13] *See Order.*

DEPARTMENT OF COMMERCE

International Trade Administration

[C–570–991]

Chlorinated Isocyanurates From the People's Republic of China: Preliminary Results of the Countervailing Duty Administrative Review and Rescission of Review, in Part; 2020

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The U.S. Department of Commerce (Commerce) preliminarily determines that countervailable subsidies are being provided to producers and exporters of chlorinated isocyanurates (chlorinated isos) from the People's Republic of China (China) during the period of review (POR), January 1, 2020, through December 31, 2020. Interested parties are invited to comment on these preliminary results.

DATES: Applicable December 6, 2022.

FOR FURTHER INFORMATION CONTACT: Genevieve Coen, AD/CVD Operations, Office V, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–3251.

SUPPLEMENTARY INFORMATION:

Background

On December 28, 2021, Commerce published a notice of initiation of an administrative review of the countervailing duty order on chlorinated isos from China.[1] On July 13, 2022, Commerce extended the time period for issuing these preliminary results by 120 days, in accordance with section 751(a)(3)(A) of the Tariff Act of 1930, as amended (the Act).[2] The revised deadline for these preliminary results is now November 30, 2022.

For a complete description of the events that followed the initiation of this review, *see* the Preliminary Decision Memorandum.[3] A list of topics discussed in the Preliminary Decision Memorandum is included at the appendix to this notice. The Preliminary 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 *http://access.trade.gov.* In addition, a complete version of the Preliminary Decision Memorandum can be accessed directly at *https://access.trade.gov/public/FRNoticesListLayout.aspx.*

Scope of the Order [4]

The products covered by the *Order* are chlorinated isos. For a complete description of the scope of the *Order, see* the Preliminary Decision Memorandum.

Rescission of Administrative Review, in Part

Pursuant to 19 CFR 351.213(d)(3), Commerce will rescind an administrative review when there are no reviewable suspended entries. Based on our analysis of U.S. Customs and Border Protection (CBP) information, we preliminarily determine that Hebei Jiheng Chemical Co., Ltd. (Jiheng) had no entries of subject merchandise during the POR. On March 3, 2022, we notified parties that we intended to rescind this administrative review with respect to Jiheng.[5] No parties commented on the notification of intent to rescind the review, in part. We are, therefore, rescinding the administrative review of Jiheng. For additional information regarding this determination, *see* the Preliminary Decision Memorandum.

Methodology

Commerce is conducting this review in accordance with section 751(a)(1)(A) of the Act. For each of the subsidy programs found countervailable, we preliminarily find that there is a subsidy, *i.e.,* a financial contribution that gives rise to a benefit to the recipient, and that the subsidy is specific.[6]

Commerce notes that, in making these findings, it relied, in part, on facts available and, because it finds that the Government of China did not act to the best of its ability to respond to Commerce's requests for information, it drew an adverse inference where appropriate in selecting from among the facts otherwise available.[7] For further information, *see* the Preliminary Decision Memorandum at ''Use of Facts Otherwise Available and Adverse Inferences.''

Preliminary Results of Review

For the period January 1, 2020, through December 31, 2020, we preliminarily find that the following net subsidy rates exist:

Company	Subsidy rate (percent *ad valorem*)
Heze Huayi Chemical Co., Ltd.	3.04
Juancheng Kangtai Chemical Co., Ltd.	1.22

Verification

Commerce received a timely request from Bio-Lab, Inc., Clearon Corp., and Occidental Chemical Corporation (collectively, the petitioners) to verify the information submitted in this administrative review.[8] As provided in section 782(i)(3) of the Act, Commerce intends to verify the information submitted by the mandatory respondents in advance of the final results of this review.

Assessment Rate

Consistent with section 751(a)(2)(C) of the Act, upon issuance of the final results, Commerce shall determine, and CBP shall assess, countervailing duties on all appropriate entries in accordance with the final results of this review. If the assessment rate calculated in the final results is zero or *de minimis,* we will instruct CBP to liquidate all appropriate entries without regard to countervailing duties. For the company for which this review is rescinded, we will instruct CBP to assess countervailing duties on all appropriate entries at a rate equal to the cash deposit of estimated countervailing duties required at the time of entry, or withdrawal from warehouse, for consumption, during the period January 1, 2020, through December 31, 2020, in accordance with 19 CFR 351.212(c)(l)(i).

For the companies remaining in the review, Commerce intends to issue assessment instructions to CBP no earlier than 35 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

Pursuant to section 751(a)(2)(C) of the Act, Commerce intends to instruct CBP to collect cash deposits of estimated countervailing duties in the amounts indicated above, except, where the rate calculated in the final results is zero or *de minimis,* no cash deposit will be required on shipments of subject merchandise entered, or withdrawn from warehouse, for consumption on or after the date of publication of the final results of this review. For all non-reviewed firms, we will instruct CBP to continue to collect cash deposits of estimated countervailing duties at the most recent company-specific or all-others rate applicable to the company, as appropriate. These cash deposit instructions, when imposed, shall remain in effect until further notice.

[1] *See Initiation of Antidumping and Countervailing Duty Administrative Reviews,* 86 FR 73734 (December 28, 2021).

[2] *See* Memorandum, ''Extension of Deadline for Preliminary Results of Countervailing Duty Administrative Review, 2020,'' dated July 13, 2022.

[3] *See* Memorandum, ''Decision Memorandum for the Preliminary Results of the Countervailing Duty Administrative Review of Chlorinated Isocyanurates from the People's Republic of China and Rescission of Administrative Review, in Part; 2020,'' dated concurrently with, and hereby adopted by, this notice (Preliminary Decision Memorandum).

[4] *See Chlorinated Isocyanurates from the People's Republic of China: Countervailing Duty Order,* 79 FR 67424 (November 13, 2014) (*Order*).

[5] *See* Memorandum, ''Notice of Intent to Rescind Review, in Part,'' dated March 3, 2022.

[6] *See* sections 771(5)(B) and (D) of the Act regarding financial contribution; section 771(5)(E) of the Act regarding benefit; and section 771(5A) of the Act regarding specificity.

[7] *See* sections 776(a) and (b) of the Act.

[8] *See* Petitioners' Letter, ''Request for Verification,'' dated March 30, 2022.

Disclosure and Public Comment

We will disclose to parties to this proceeding the calculations performed in reaching the preliminary results within five days of the date of publication of these preliminary results.[9] Case briefs or other written comments may be submitted to the Assistant Secretary for Enforcement and Compliance. A timeline for the submission of case and rebuttal briefs will be provided to interested parties at a later date. Parties who submit case or rebuttal briefs in this proceeding are encouraged to submit with each argument: (1) a statement of the issue; (2) a brief summary of the argument; and (3) a table of authorities.[10] Case and rebuttal briefs should be filed using ACCESS [11] and must be served on interested parties.[12] Executive summaries should be limited to five pages total, including footnotes. Note that Commerce has temporarily modified certain of its requirements for serving documents containing business proprietary information, until further notice.[13]

Pursuant to 19 CFR 351.310(c), interested parties who wish to request a hearing, limited to issues raised in the case and rebuttal briefs, must submit a written request to the Assistant Secretary for Enforcement and Compliance, U.S. Department of Commerce, filed electronically using ACCESS by 5:00 p.m. Eastern Time within 30 days after the date of publication of this notice.[14] Requests should contain: (1) the party's name, address, and telephone number; (2) the number of participants and whether any participant is a foreign national; and (3) a list of the issues to be discussed. Issues raised in the hearing will be limited to those raised in the respective case and rebuttal briefs.[15] If a request for a hearing is made, Commerce intends to hold the hearing at a time and date to be determined. Parties should confirm the date and time of the hearing two days before the scheduled date. Parties are reminded that all briefs and hearing requests must be filed electronically using ACCESS and received successfully in their entirety by 5:00 p.m. Eastern Time on the due date.

Final Results of Review

Unless the deadline is extended pursuant to section 751(a)(3)(A) of the Act, Commerce intends to issue the final results of this administrative review, including the results of our analysis of the issues raised by the parties in their comments, within 120 days after publication of these preliminary results.

Notification to Interested Parties

This administrative review and notice are issued and published in accordance with sections 751(a)(1) and 777(i)(1) of the Act, and 19 CFR 351.213.

Dated: November 29, 2022.

Lisa W. Wang,

Assistant Secretary for Enforcement and Compliance.

Appendix

List of Topics Discussed in the Preliminary Decision Memorandum

I. Summary
II. Background
III. Scope of the *Order*
IV. Rescission of Administrative Review, in Part
V. Diversification of China's Economy
VI. Use of Facts Otherwise Available and Adverse Inferences
VII. Subsidies Valuation
VIII. Benchmarks
IX. Analysis of Programs
X. Recommendation

[FR Doc. 2022–26459 Filed 12–5–22; 8:45 am]

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DEPARTMENT OF COMMERCE

International Trade Administration

[A–533–867]

Welded Stainless Pressure Pipe From India: Preliminary Results and Partial Rescission of Antidumping Duty Administrative Review; 2020–2021

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The U.S. Department of Commerce (Commerce) preliminarily finds that Ratnamani Metals & Tubes Ltd. (Ratnamani) made sales of subject merchandise at less than normal value (NV) in the United States during the November 1, 2020, through October 31, 2021, period of review (POR). We are also rescinding this review for Hindustan Inox, Ltd. (Hindustan Inox) where timely requests for withdrawal were filed by the party who requested its review. We invite interested parties to comment on these preliminary results.

DATES: Applicable December 6, 2022.

FOR FURTHER INFORMATION CONTACT: John Conniff, AD/CVD Operations, Office III, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–1009.

SUPPLEMENTARY INFORMATION:

Background

On November 17, 2016, Commerce published the antidumping duty order in the **Federal Register**.[1] On December 28, 2021, pursuant to section 751(a)(1) of the Tariff Act of 1930, as amended (the Act), Commerce initiated an administrative review of the *Order*.[2] On July 19, 2022, we extended the deadline for the preliminary results to November 30, 2022.[3]

Commerce initiated this administrative review covering the following companies: Apex Tubes Private Ltd.; Apurvi Industries; Arihant Tubes; Divine Tubes Pvt. Ltd.; Heavy Metal & Tubes; Hindustan Inox; J.S.S. Steelitalia Ltd.; Linkwell Seamless Tubes Private Limited; Maxim Tubes Company Pvt. Ltd.; MBM Tubes Pvt. Ltd.; Mukat Tanks & Vessel Ltd.; Neotiss Ltd.; Prakash Steelage Ltd.; Quality Stainless Pvt. Ltd.; Raajratna Metal Industries Ltd.; Ratnadeep Metal & Tubes Ltd.; Ratnamani; Remi Edelstahl Tubulars; Shubhlaxmi Metals & Tubes Private Limited; SLS Tubes Pvt. Ltd.; and Steamline Industries Ltd.[4]

On January 25, 2022, we limited the number of respondents selected for individual examination in this administrative review to Hindustan Inox and Ratnamani.[5] We did not select the remaining companies for individual examination, and these companies remain subject to this administrative review.

Scope of the Order

The products covered by the scope of the *Order* are welded stainless pressure pipe from India. For a complete description of the scope, *see* the Preliminary Decision Memorandum.[6]

Methodology

Commerce is conducting this review in accordance with section 751(a)(2) of

[9] *See* 19 CFR 351.224(b).

[10] *See* 19 CFR 351.309(c)(2) and (d)(2).

[11] *See generally* 19 CFR 351.303.

[12] *See* 19 CFR 351.303(f).

[13] *See Temporary Rule.*

[14] *See* 19 CFR 351.310(c).

[15] *See* 19 CFR 351.310.

[1] *See Welded Stainless Pressure Pipe from India: Antidumping and Countervailing Duty Orders,* 81 FR 81062 (November 17, 2016) *(Order).*

[2] *See Initiation of Antidumping Duty and Countervailing Duty Administrative Reviews,* 86 FR 73734 (December 28, 2021) (*Initiation Notice*).

[3] *See* Memorandum, ''Extension of Deadline for the Preliminary Results,'' dated July 19, 2022.

[4] *See Initiation Notice,* 86 FR at 73736.

[5] *See* Memorandum, ''Respondent Selection,'' dated January 25, 2022.

[6] *See* Memorandum, ''Decision Memorandum for the Preliminary Results and Partial Recission of the Administrative Review of the Antidumping Duty Order on Welded Stainless Pressure Pipe from India; 2020–2021,'' dated concurrently with, and hereby adopted by, this notice (Preliminary Decision Memorandum).

the Act. Export price was calculated in accordance with section 772 of the Act. Normal value was calculated in accordance with section 773 of the Act. For a full description of the methodology underlying our conclusions, *see* the Preliminary Decision Memorandum. A list of topics included in the Preliminary Decision Memorandum is included in Appendix I to this notice. The Preliminary 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 Preliminary Decision Memorandum can be accessed directly at *https://access.trade.gov/public/FRNoticesListLayout.aspx.*

Partial Rescission of Administrative Review

Pursuant to 19 CFR 351.213(d)(1), Commerce will rescind an administrative review, in whole or in part, if the parties that requested a review withdraw the request within 90 days of the date of publication of the notice of initiation. Commerce received a timely-filed withdrawal request from Felker Brothers Corporation (the petitioner), on March 28, 2022, withdrawing its request for Hindustan Inox.[7] Because the withdrawal request was timely filed, and no other party requested a review of the company, in accordance with 19 CFR 351.213(d)(1), Commerce is rescinding this review of the *Order* with respect to Hindustan Inox.

Non-Individually Examined Companies

For the rate for non-selected companies in an administrative review, generally, Commerce looks to section 735(c)(5) of the Act, which provides instructions for calculating the all-others rate in a market economy investigation. Under section 735(c)(5)(A) of the Act, the all-others rate is normally ''an amount equal to the weighted average of the estimated weighted-average dumping margins established for exporters and producers individually investigated, excluding any zero or *de minimis* margins, and any margins determined entirely {on the basis of facts available}.'' We preliminarily calculated a margin for Ratnamani that was not zero, *de minimis,* or based on facts available. Accordingly, we have preliminarily applied the margin calculated for Ratnamani to the non-selected companies.

[7] *See* Petitioner's Letter, ''Partial Withdrawal of Request for Administrative Review,'' dated March 28, 2022.

Preliminary Results of Review

We preliminarily determine that, for the period November 1, 2020, through October 31, 2021, the following weighted-average dumping margins exist:

Exporter/producer	Weighted-average dumping margin (percent)
Ratnamani Metals & Tubes Ltd ..	34.32
Non-Selected Companies [8]	34.32

Disclosure and Public Comment

We intend to disclose the calculations performed for these preliminary results to parties within five days after the date of publication of this notice.[9]

Pursuant to 19 CFR 351.309(c), interested parties may submit case briefs not later than 30 days after the date of publication of this notice.[10] Rebuttal briefs, limited to issues raised in the case briefs, may be filed not later than seven days after the date for filing case briefs.[11] Parties who submit case or rebuttal briefs in this proceeding are encouraged to submit with each argument: (1) a statement of the issue; (2) a brief summary of the argument; and (3) a table of authorities.[12] Case and rebuttal briefs should be filed using ACCESS.[13] Note that Commerce has temporarily modified certain of its requirements for serving documents containing business proprietary information, until further notice.[14]

Interested parties who wish to request a hearing must submit a written request to the Assistant Secretary for Enforcement and Compliance within 30 days of the date of publication of this notice.[15] Requests should contain: (1) the party's name, address and telephone number; (2) the number of participants; and (3) a list of issues parties intend to discuss. Issues raised in the hearing will be limited to those raised in the respective case and rebuttal briefs. If a request for a hearing is made, Commerce intends to hold the hearing at a time and date to be determined. Parties should confirm by telephone the date, time, and location of the hearing two days before the scheduled date.

[8] *See* Appendix II for a full list of companies not individually examined in this review.

[9] *See* 19 CFR 351.224(b).

[10] *See* 19 CFR 351.309(c)(1)(ii).

[11] *See* 19 CFR 351.309(d)(1).

[12] *See* 19 CFR 351.309(c)(2) and (d)(2).

[13] *See* 19 CFR 351.303.

[14] *See Temporary Rule Modifying AD/CVD Service Requirements Due to COVID–19; Extension of Effective Period,* 85 FR 41363 (July 10, 2020).

[15] *See* 19 CFR 351.310(c).

Unless extended, we intend to issue the final results of this administrative review, which will include the results of our analysis of all issues raised in the case and rebuttal briefs, within 120 days of publication of these preliminary results in the **Federal Register**, pursuant to section 751(a)(3)(A) of the Act, unless extended.

Assessment Rates

Upon completion of the administrative review, Commerce shall determine, and U.S. Customs and Border Protection (CBP) shall assess, antidumping duties on all appropriate entries. If the weighted-average dumping margin for Ratnamani is not zero or *de minimis* (*i.e.,* less than 0.50 percent) in the final results of this review, we will calculate importer-specific *ad valorem* duty assessment rates for the merchandise based on the ratio of the total amount of dumping calculated for the examined sales made during the POR to each importer and the total entered value of those same sales, in accordance with 19 CFR 351.212(b)(1). Where an importer-specific *ad valorem* assessment rate is zero or *de minimis* in the final results of review, we will instruct CBP to liquidate the appropriate entries without regard to antidumping duties, in accordance with 19 CFR 351.106(c)(2). If a respondent's weighted-average dumping margin is zero or *de minimis* in the final results of review, we will instruct CBP to liquidate the appropriate entries without regard to antidumping duties, in accordance with the *Final Modification for Reviews, i.e.,* ''{w}here the weighted-average margin of dumping for the exporter is determined to be zero or *de minimis,* no antidumping duties will be assessed.'' [16] For entries of subject merchandise during the POR produced by each respondent for which the producer did not know its merchandise was destined for the United States, we will instruct CBP to liquidate unreviewed entries at the all-others rate if there is no rate for the intermediate company (or

[16] *See Antidumping Proceedings: Calculation of the Weighted-Average Dumping Margin and Assessment Rate in Certain Antidumping Proceedings; Final Modification,* 77 FR 8101, 8102 (February 14, 2012) (*Final Modification for Reviews*).

companies) involved in the transaction.[17]

For the companies which were not individually examined, we intend to assign an assessment rate based on the review-specific average rate, calculated as noted in the ''Preliminary Results of Review'' section, above. The final results of this review shall be the basis for the assessment of antidumping duties on entries of merchandise covered by this review and for future deposits of estimated duties, where applicable.[18] Commerce intends to issue assessment instructions to CBP no earlier than 35 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 deposit requirements will be effective upon the publication of the final results of this administrative review 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 each specific company listed above will be that established in the final results of this administrative 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 previously reviewed or investigated companies not listed above, the cash deposit rate will continue to be the company-specific rate published for the most recently completed segment of this proceeding in which the producer or exporter participated; (3) if the exporter is not a firm covered in this review, a prior review, or the investigation but the producer is, the cash deposit rate will be the rate established for the most recently completed segment of this proceeding for the producer of the merchandise; and (4) the cash deposit rate for all other producers or exporters will continue to be the all-others rate of 8.35 percent.[19] These cash deposit requirements, when imposed, shall remain in effect until further notice.

[17] *See Antidumping and Countervailing Duty Proceedings: Assessment of Antidumping Duties,* 68 FR 23954 (May 6, 2003).

[18] *See* section 751(a)(2)(C) of the Act.

[19] *See Order,* 81 FR at 81063.

Notification to Importers

This notice also serves as a preliminary reminder to importers of their responsibility under 19 CFR 351.402(f)(2) to file a certificate regarding the reimbursement of antidumping and/or countervailing duties prior to liquidation of the relevant entries during this review period. Failure to comply with this requirement could result in the Commerce's presumption that reimbursement of antidumping and/or countervailing duties occurred and the subsequent assessment of double antidumping duties, and/or an increase in the amount of antidumping duties by the amount of the countervailing duties.

Notification to Interested Parties

We are issuing and publishing these preliminary results in accordance with sections 751(a)(1) and 777(i)(1) of the Act and 19 CFR 351.221(b)(4).

Dated: November 29, 2022.

Lisa W. Wang,

Assistant Secretary for Enforcement and Compliance.

Appendix I

List of Topics Discussed in the Preliminary Decision Memorandum

I. Summary
II. Background
III. Scope of the *Order*
IV. Partial Rescission of Review
V. Companies Not Selected for Individual Examination
VI. Discussion of the Methodology
VII. Currency Conversion
VIII. Recommendation

Appendix II

List of Companies Not Selected for Individual Examination

1. Apex Tubes Private Ltd.
2. Apurvi Industries
3. Arihant Tubes
4. Divine Tubes Pvt. Ltd.
5. Heavy Metal & Tubes
6. J.S.S. Steelitalia Ltd.
7. Linkwell Seamless Tubes Private Limited
8. Maxim Tubes Company Pvt. Ltd.
9. MBM Tubes Pvt. Ltd.
10. Mukat Tanks & Vessel Ltd.
11. Neotiss Ltd.
12. Prakash Steelage Ltd.
13. Quality Stainless Pvt. Ltd.
14. Raajratna Metal Industries Ltd.
15. Ratnadeep Metal & Tubes Ltd.
16. Remi Edelstahl Tubulars
17. Shubhlaxmi Metals & Tubes Private Limited
18. SLS Tubes Pvt. Ltd.
19. Steamline Industries Ltd.

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

[RTID 0648–XC564]

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 Woodside Energy, L.L.C. (Woodside) for the take of marine mammals incidental to geophysical survey activity in the Gulf of Mexico.

DATES: The LOA is effective from December 15, 2022, through June 15, 2023.

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: Ben Laws, 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

Woodside plans to conduct a Zero Offset Vertical Seismic Profile (VSP) survey within East Breaks Block 699. See Section H of Woodside's application for a map. Woodside plans to use either a 6-element, 1,500 cubic inch (in^3) airgun array or a 12-element, 2,400 in^3 airgun array. Please see Woodside's application for additional detail.

Consistent with the preamble to the final rule, the survey effort proposed by Woodside 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, 5398, 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 these survey types. Summary descriptions of these modeled survey geometries are available in the preamble to the proposed rule (83 FR 29212, 29220, June 22, 2018). Coil was selected as the best available proxy survey type for Woodside's VSP survey because the spatial coverage of the planned surveys is most similar to the coil survey pattern. For the planned survey, the seismic source array will be deployed in the following stationary form: 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. The coil survey pattern in the model was assumed to cover approximately 144 kilometers squared (km^2) per day (compared with approximately 795 km^2, 199 km^2, and 845 km^2 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 Woodside's planned survey is expected to cover no additional area as a stationary source, or 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 Woodside in terms of predicted Level B harassment.

In addition, all available acoustic exposure modeling results assume use of a 72-element, 8,000 in^3 array. Thus, estimated take numbers for this LOA are considered conservative due to the differences in both the airgun array (6 or 12 elements, 1,500 or 2,400 in^3), and in daily survey area planned by Woodside (as mentioned above), as compared to those modeled for the rule.

The survey is planned to occur for a maximum of 2 days in Zone 6. The survey is planned to occur in winter, but may occur in either 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).

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, 5442 (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 certain marine mammal species produces results inconsistent with what is known regarding their occurrence in the GOM.

[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).

Accordingly, we have adjusted the calculated take estimates for those species as described below.

NMFS' final rule described a ''core habitat area'' for Rice's whales (formerly known as GOM Bryde's whales) [3] located in the northeastern GOM in waters between 100–400 m depth along the continental shelf break (Rosel *et al.,* 2016). However, whaling records suggest that Rice's whales historically had a broader distribution within similar habitat parameters throughout the GOM (Reeves *et al.,* 2011; Rosel and Wilcox, 2014). In addition, habitat-based density modeling identified similar habitat (*i.e.,* approximately 100–400 m water depths along the continental shelf break) as being potential Rice's whale habitat (Roberts *et al.,* 2016), although the core habitat area contained approximately 92 percent of the predicted abundance of Rice's whales. See discussion provided at, *e.g.,* 83 FR 29228, 83 FR 29280 (June 22, 2018); 86 FR 5418 (January 19, 2021).

Although Rice's whales may occur outside of the core habitat area, we expect that any such occurrence would be limited to the narrow band of suitable habitat described above (*i.e.,* 100–400 m) and that, based on the few available records, these occurrences would be rare. Woodside's planned activities will occur in water depths of approximately 941 m in the northern GOM. Thus, NMFS does not expect there to be the reasonable potential for take of Rice's whale in association with this survey and, accordingly, does not authorize take of Rice's whale through this LOA.

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 less than 20 occasions during the 1992–2009 NOAA surveys (Fraser's dolphin and false killer whale).[4] 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 to 1–30 m depth than to deeper waters, with an average depth during those most common dives of approximately 3 m.

In summary, killer whales are the most rarely encountered species in the GOM and typically occur only in particularly deep water. 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-in^3 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 would 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 past authorizations, NMFS has often addressed situations involving the low likelihood of encountering a rare species such as killer whales in the GOM through authorization of take of a single group of average size (*i.e.,* representing a single potential encounter). See 83 FR 63268, December 7, 2018. See also 86 FR 29090, May 28, 2021; 85 FR 55645, September 9, 2020. For Woodside's survey, use of the exposure modeling produces an estimate of one killer whale exposure. Given the foregoing discussion, it is unlikely that any killer whales would be encountered during this 2-day survey, and accordingly, no take of killer whales is authorized through the Woodside LOA.

Based on the results of our analysis, NMFS has determined that the level of taking 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

[3] The final rule refers to the GOM Bryde's whale (*Balaenoptera edeni*). These whales were subsequently described as a new species, Rice's whale (*Balaenoptera ricei*) (Rosel *et al.,* 2021).

[4] However, note that these species have been observed over a greater range of water depths in the GOM than have killer whales.

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	48	2,207	2.2
Kogia spp	[3] 11	4,373	0.2
Beaked whales	182	3,768	4.8
Rough-toothed dolphin	34	4,853	0.7
Bottlenose dolphin	101	176,108	0.1
Clymene dolphin	131	11,895	1.1
Atlantic spotted dolphin	42	74,785	0.1
Pantropical spotted dolphin	304	102,361	0.3
Spinner dolphin	7	25,114	0
Striped dolphin	34	5,229	0.6
Fraser's dolphin	12	1,665	0.7
Risso's dolphin	25	3,764	0.7
Melon-headed whale	65	7,003	0.9
Pygmy killer whale	15	2,126	0.7
False killer whale	25	3,204	0.8
Killer whale	0	267	n/a
Short-finned pilot whale	38	1,981	1.9

[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 the killer whale, the larger estimated SAR abundance estimate is used.
[3] Includes 1 take by Level A harassment and 10 takes by Level B harassment.

Based on the analysis contained herein of Woodside'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 and therefore 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 Woodside authorizing the take of marine mammals incidental to its geophysical survey activity, as described above.

Dated: December 1, 2022.

Kimberly Damon-Randall,

Director, Office of Protected Resources, National Marine Fisheries Service.

[FR Doc. 2022–26485 Filed 12–5–22; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF EDUCATION

[Docket No.: ED–2022–SCC–0149]

Agency Information Collection Activities; Comment Request; Targeted Teacher Shortage Areas Data Collection

AGENCY: Office of Postsecondary Education, Department of Education (ED).

ACTION: Notice

SUMMARY: In accordance with the Paperwork Reduction Act (PRA) of 1995, the Department is proposing an extension without change of a currently approved information collection request (ICR).

DATES: Interested persons are invited to submit comments on or before February 6, 2023.

ADDRESSES: To access and review all the documents related to the information collection listed in this notice, please use *http://www.regulations.gov* by searching the Docket ID number ED–2022–SCC–0149. Comments submitted in response to this notice should be submitted electronically through the Federal eRulemaking Portal at *http://www.regulations.gov* by selecting the Docket ID number or via postal mail, commercial delivery, or hand delivery. If the regulations.gov site is not available to the public for any reason, the Department will temporarily accept comments at *ICDocketMgr@ed.gov.* Please include the docket ID number and the title of the information collection request when requesting documents or submitting comments.

Please note that comments submitted after the comment period will not be accepted. Written requests for information or comments submitted by postal mail or delivery should be addressed to the Manager of the Strategic Collections and Clearance Governance and Strategy Division, U.S. Department of Education, 400 Maryland Ave. SW, LBJ, Room 6W203, Washington, DC 20202–8240.

FOR FURTHER INFORMATION CONTACT: For specific questions related to collection activities, please contact Freddie Cross, 202–453–7224.

SUPPLEMENTARY INFORMATION: The Department, in accordance with the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3506(c)(2)(A)), provides the general public and Federal agencies with an opportunity to comment on proposed, revised, and continuing collections of information. This helps the Department assess the impact of its information collection requirements and minimize the public's reporting burden. It also helps the public understand the Department's information collection requirements and provide the requested data in the desired format. The Department is soliciting comments on the proposed information collection request (ICR) that is described below. The Department is especially interested in public comment addressing the following issues: (1) is this collection necessary to the proper functions of the Department; (2) will this information be processed and used in a timely manner; (3) is the estimate of burden accurate; (4) how might the Department enhance the quality, utility, and clarity of the information to be collected; and (5) how might the Department minimize the burden of this collection on the respondents, including through the use of information technology. Please note that written comments received in response to this notice will be considered public records.

Title of Collection: Targeted Teacher Shortage Areas Data Collection.

OMB Control Number: 1840–0595.

Type of Review: An extension without change of a currently approved ICR.

Respondents/Affected Public: State, Local, and Tribal Governments.

Total Estimated Number of Annual Responses: 57.

Total Estimated Number of Annual Burden Hours: 2,793.

Abstract: This request is for approval of reporting requirements that are contained in the Federal Family Education Loan Program (FFELP) regulations (34 CFR 682.210) which address the targeted teacher deferment provision of the Higher Education Act of 1965 as amended by the Higher Education Amendment of 1986, sections 427(a)(2)(C)(vi), 428 (b)(1)(M)(vi), and 428 (b)(4)(A), which provide for the targeted teacher deferment. The FFELP (34 CFR 682.210(q)), Paul Douglas Teacher Scholarship Program (34 CFR 653.50(a)), TEACH Grant Program, and Federal Perkins Loan Program (34 CFR 674.53(c)) regulations contain information collection requirements. The Chief State School Officers of each state provide the Secretary annually with a database of proposed teacher shortage areas for each state.

Dated: December 1, 2022.

Kun Mullan,

PRA Coordinator, Strategic Collections and Clearance, Governance and Strategy Division, Office of Chief Data Officer, Office of Planning, Evaluation and Policy Development.

[FR Doc. 2022–26497 Filed 12–5–22; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

[Docket No.: ED–2022–SCC–0121]

Agency Information Collection Activities; Submission to the Office of Management and Budget for Review and Approval; Comment Request; Lender's Request for Payment of Interest and Special Allowance—LaRS

AGENCY: Federal Student Aid (FSA), Department of Education (ED).

ACTION: Notice.

SUMMARY: In accordance with the Paperwork Reduction Act (PRA) of 1995, the Department is proposing an extension without change of a currently approved information collection request (ICR).

DATES: Interested persons are invited to submit comments on or before January 5, 2023.

ADDRESSES: Written comments and recommendations for proposed information collection requests should be submitted within 30 days of publication of this notice. Click on this link *www.reginfo.gov/public/do/PRAMain* to access the site. Find this information collection request (ICR) by selecting ''Department of Education'' under ''Currently Under Review,'' then check the ''Only Show ICR for Public Comment'' checkbox. *Reginfo.gov* provides two links to view documents related to this information collection request. Information collection forms and instructions may be found by clicking on the ''View Information Collection (IC) List'' link. Supporting statements and other supporting documentation may be found by clicking on the ''View Supporting Statement and Other Documents'' link.

FOR FURTHER INFORMATION CONTACT: For specific questions related to collection activities, please contact Beth Grebeldinger, 202–377–4018.

SUPPLEMENTARY INFORMATION: The Department is especially interested in public comment addressing the following issues: (1) is this collection necessary to the proper functions of the Department; (2) will this information be processed and used in a timely manner; (3) is the estimate of burden accurate; (4) how might the Department enhance the quality, utility, and clarity of the information to be collected; and (5) how might the Department minimize the burden of this collection on the respondents, including through the use of information technology. Please note that written comments received in response to this notice will be considered public records.

Title of Collection: Lender's Request for Payment of Interest and Special Allowance—LaRS.

OMB Control Number: 1845–0013.

Type of Review: An extension without change of a currently approved ICR.

Respondents/Affected Public: Private Sector.

Total Estimated Number of Annual Responses: 1,452.

Total Estimated Number of Annual Burden Hours: 3,539.

Abstract: The Department of Education (the Department) is submitting the Lender's Interest and Special Allowance Request & Report, ED Form 799 for extension of the current OMB approval. The information collected on the ED Form 799 is needed to pay interest and special allowance to holders of Federal Family Education Loans, for internal financial reporting, budgetary projections, and for audit and lender reviews by the Department, Servicers, External Auditors and Government Accountability Office (GAO). The legal authority for collecting this information is Title IV, Part B of the Higher Education Act of 1965, as amended by the Higher Education Reconciliation Act of 2005 (''the HERA''), (Pub. L. 109–171). The Department is requesting the continual approval for regulatory sections 682.304 and 682.414.

Dated: December 1, 2022.

Kun Mullan,

PRA Coordinator, Strategic Collections and Clearance Governance and Strategy Division, Office of Chief Data Officer, Office of Planning, Evaluation and Policy Development.

[FR Doc. 2022–26470 Filed 12–5–22; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #1

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER22–2898–001.
Applicants: Huck Finn Solar, LLC.
Description: Tariff Amendment: Response to Request for Additional Information of Huck Finn Solar to be effective 11/21/2022.
Filed Date: 11/30/22.
Accession Number: 20221130–5187.
Comment Date: 5 p.m. ET 12/21/22.

Docket Numbers: ER23–272–000.
Applicants: Avangrid Renewables, LLC.
Description: Refund Report: Refund Report to be effective N/A.
Filed Date: 11/30/22.
Accession Number: 20221130–5102.
Comment Date: 5 p.m. ET 12/21/22.

Docket Numbers: ER23–509–000.
Applicants: El Paso Electric Company.
Description: § 205(d) Rate Filing: Service Agreement No. 367, EPE and Solar PV Development to be effective 1/28/2023.
Filed Date: 11/29/22.
Accession Number: 20221129–5205.
Comment Date: 5 p.m. ET 12/20/22.

Docket Numbers: ER23–510–000
Applicants: Midcontinent Independent System Operator, Inc.
Description: § 205(d) Rate Filing: 2022–11–30_SA 3740 Entergy Louisiana-Willis Pond 1st Rev GIA (J1421) to be effective 1/30/2023.
Filed Date: 11/30/22.
Accession Number: 20221130–5039.
Comment Date: 5 p.m. ET 12/21/22.

Docket Numbers: ER23–511–000.
Applicants: American Electric Power Service Corporation, Southwest Power Pool, Inc.
Description: § 205(d) Rate Filing: American Electric Power Service Corporation submits tariff filing per 35.13(a)(2)(iii: AEP West Transcos and AEP West Operating Cos Formula Rate Revisions to be effective 2/1/2023.
Filed Date: 11/30/22.
Accession Number: 20221130–5107.
Comment Date: 5 p.m. ET 12/21/22.

Docket Numbers: ER23–512–000.
Applicants: PJM Interconnection, L.L.C.
Description: § 205(d) Rate Filing: Amendment to ISA, Service Agreement No. 6007; Queue No. AD2–115 to be effective 3/15/2021.
Filed Date: 11/30/22.
Accession Number: 20221130–5118.
Comment Date: 5 p.m. ET 12/21/22.

Docket Numbers: ER23–513–000.
Applicants: Midcontinent Independent System Operator, Inc., Great River Energy.
Description: § 205(d) Rate Filing: Midcontinent Independent System Operator, Inc. submits tariff filing per 35.13(a)(2)(iii: 2022–11–30_GRE Revisions to Formula Rates and Transmission Rate Incentives to be effective 2/1/2023.
Filed Date: 11/30/22.
Accession Number: 20221130–5126.
Comment Date: 5 p.m. ET 12/21/22.

Docket Numbers: ER23–514–000.
Applicants: Alabama Power Company, Georgia Power Company, Mississippi Power Company.
Description: Tariff Amendment: Alabama Power Company submits tariff filing per 35.15: FP&L NITSA Termination Filing to be effective 10/31/2022.
Filed Date: 11/30/22.
Accession Number: 20221130–5152.
Comment Date: 5 p.m. ET 12/21/22.

Docket Numbers: ER23–515–000.
Applicants: Alabama Power Company, Georgia Power Company, Mississippi Power Company.
Description: § 205(d) Rate Filing: Alabama Power Company submits tariff filing per 35.13(a)(2)(iii: Wadley Solar LGIA Amendment Filing to be effective 11/28/2022.
Filed Date: 11/30/22.
Accession Number: 20221130–5160.
Comment Date: 5 p.m. ET 12/21/22.

Docket Numbers: ER23–516–000.
Applicants: Frederickson Power L.P.
Description: § 205(d) Rate Filing: Tariff Revision Category 1 (11.30.22) to be effective 12/1/2022.
Filed Date: 11/30/22.
Accession Number: 20221130–5181.
Comment Date: 5 p.m. ET 12/21/22.

Docket Numbers: ER23–517–000.
Applicants: ISO New England Inc., New England Power Pool Participants Committee.
Description: § 205(d) Rate Filing: ISO New England Inc. submits tariff filing per 35.13(a)(2)(iii: ISO–NE/NEPOOL; Revisions to Incorporate Solar Resources into DNE Dispatch Rules to be effective 12/5/2023.
Filed Date: 11/30/22.
Accession Number: 20221130–5203.
Comment Date: 5 p.m. ET 12/21/22.

The filings are accessible in the Commission's eLibrary system (*https://elibrary.ferc.gov/idmws/search/fercgensearch.asp*) by querying the docket number.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5:00 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: November 30, 2022.

Kimberly D. Bose,

Secretary.

[FR Doc. 2022–26478 Filed 12–5–22; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings

Take notice that the Commission has received the following Natural Gas Pipeline Rate and Refund Report filings:

Filings Instituting Proceedings

Docket Numbers: PR23–12–000.
Applicants: Dow Pipeline Company.
Description: § 284.123 Rate Filing: Petition for Rate Approval to be effective 12/1/2022.
Filed Date: 11/29/22.
Accession Number: 20221129–5139.
Comment Date: 5 p.m. ET 12/20/22.

Docket Numbers: PR23–13–000.
Applicants: The East Ohio Gas Company.
Description: § 284.123(g) Rate Filing: Operating Statement of The East Ohio Gas Company 11/2/2022 to be effective 11/2/2022.
Filed Date: 11/30/22.
Accession Number: 20221130–5003.
Comment Date: 5 p.m. ET 12/21/22.
184.123(g) Protest: 5 p.m. ET 1/30/23.

Docket Numbers: PR23–14–000.
Applicants: Public Service Company of Colorado.
Description: § 284.123(g) Rate Filing: Statement of Rates & Statement of Op.

Conditions_eff 11.1.22 to be effective 11/1/2022.

Filed Date: 11/30/22.

Accession Number: 20221130–5063.

Comment Date: 5 p.m. ET 12/21/22.

184.123(g) Protest: 5 p.m. ET 1/30/23.

Docket Numbers: RP23–213–000.

Applicants: Rockies Express Pipeline LLC.

Description: § 4(d) Rate Filing: REX 2022–11–29 Negotiated Rate Agreement Amendment to be effective 11/28/2022.

Filed Date: 11/29/22.

Accession Number: 20221129–5123.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–214–000.

Applicants: Chandeleur Pipe Line, LLC.

Description: Compliance filing: Chandeleur FLLA Filing to be effective N/A.

Filed Date: 11/29/22.

Accession Number: 20221129–5186.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–215–000.

Applicants: Kinder Morgan Louisiana Pipeline LLC.

Description: § 4(d) Rate Filing: Fuel Adjustment Effective January 1, 2023 to be effective 1/1/2023.

Filed Date: 11/30/22.

Accession Number: 20221130–5000.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–216–000.

Applicants: Southern Natural Gas Company, L.L.C.

Description: § 4(d) Rate Filing: Spire Negotiated Rate Dec 2022 to be effective 12/1/2022.

Filed Date: 11/30/22.

Accession Number: 20221130–5022.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–217–000.

Applicants: MountainWest Overthrust Pipeline, LLC.

Description: § 4(d) Rate Filing: Company Contact Information to be effective 1/1/2023.

Filed Date: 11/30/22.

Accession Number: 20221130–5061.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–218–000.

Applicants: Colorado Interstate Gas Company, L.L.C.

Description: § 4(d) Rate Filing: ATC Update Filing—Totem 2022–2023 to be effective 12/1/2022.

Filed Date: 11/30/22.

Accession Number: 20221130–5062.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–219–000.

Applicants: White River Hub, LLC.

Description: § 4(d) Rate Filing: Company Contact Information to be effective 1/1/2023.

Filed Date: 11/30/22.

Accession Number: 20221130–5066.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–220–000.

Applicants: El Paso Natural Gas Company, L.L.C.

Description: § 4(d) Rate Filing: Negotiated Rate Agmt Update (Conoco—Dec 22) to be effective 12/1/2022.

Filed Date: 11/30/22.

Accession Number: 20221130–5072.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–221–000.

Applicants: MountainWest Pipeline, LLC.

Description: § 4(d) Rate Filing: Company Contact Information to be effective 1/1/2023.

Filed Date: 11/30/22.

Accession Number: 20221130–5076.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–222–000.

Applicants: MountainWest Pipeline, LLC.

Description: § 4(d) Rate Filing: FGRP Report for 2023 to be effective 1/1/2023.

Filed Date: 11/30/22.

Accession Number: 20221130–5079.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–223–000.

Applicants: El Paso Natural Gas Company, L.L.C.

Description: § 4(d) Rate Filing: Negotiated Rate Agreement Filing (MIECO #618189) to be effective 12/1/2022.

Filed Date: 11/30/22.

Accession Number: 20221130–5086.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–224–000.

Applicants: El Paso Natural Gas Company, L.L.C.

Description: § 4(d) Rate Filing: Negotiated Rate Agreements Update (Red Willow #FT3HM000 and EOG #617664)) to be effective 1/1/2023.

Filed Date: 11/30/22.

Accession Number: 20221130–5097.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–225–000.

Applicants: Young Gas Storage Company, Ltd.

Description: § 4(d) Rate Filing: Annual Fuel Filing 2022 to be effective 1/1/2023.

Filed Date: 11/30/22.

Accession Number: 20221130–5110.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–226–000.

Applicants: TransColorado Gas Transmission Company LLC.

Description: § 4(d) Rate Filing: TC Quarterly FL&U Update Nov. 2022 to be effective 1/1/2023.

Filed Date: 11/30/22.

Accession Number: 20221130–5125.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–227–000.

Applicants: Transcontinental Gas Pipe Line Company, LLC.

Description: § 4(d) Rate Filing: Negotiated Rates—Cherokee AGL—Replacement Shippers—Dec 2022 to be effective 12/1/2022.

Filed Date: 11/30/22.

Accession Number: 20221130–5142.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–228–000.

Applicants: UGI Sunbury, LLC.

Description: Annual Report of Operational Purchases and Sales of UGI Sunbury, LLC.

Filed Date: 11/30/22.

Accession Number: 20221130–5153.

Comment Date: 5 p.m. ET 12/12/22.

Docket Numbers: RP23–229–000.

Applicants: Gulf Run Transmission, LLC.

Description: § 4(d) Rate Filing: NRA—Golden Pass LNG Terminal LLC to be effective 1/1/2023.

Filed Date: 11/30/22.

Accession Number: 20221130–5167.

Comment Date: 5 p.m. ET 12/12/22.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5:00 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

Filings in Existing Proceedings

Docket Numbers: RP22–823–000.

Applicants: Wyoming Interstate Company, L.L.C.

Description: Refund Report: WIC's Refund Report in Docket No. RP22–823–000 to be effective N/A.

Filed Date: 11/8/22.

Accession Number: 20221108–5131.

Comment Date: 5 p.m. ET 12/7/22.

Any person desiring to protest in any the above proceedings must file in accordance with Rule 211 of the Commission's Regulations (18 CFR 385.211) on or before 5:00 p.m. Eastern time on the specified comment date.

The filings are accessible in the Commission's eLibrary system (*https://elibrary.ferc.gov/idmws/search/fercgensearch.asp*) by querying the docket number.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: November 30, 2022.

Kimberly D. Bose,

Secretary.

[FR Doc. 2022–26477 Filed 12–5–22; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER23–489–000]

Neptune Energy Center, LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of Neptune Energy Center, LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is December 20, 2022.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically may mail similar pleadings to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426. Hand delivered submissions in docketed proceedings should be delivered to Health and Human Services, 12225 Wilkins Avenue, Rockville, Maryland 20852.

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*http://www.ferc.gov*) using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. At this time, the Commission has suspended access to the Commission's Public Reference Room, due to the proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19), issued by the President on March 13, 2020. For assistance, contact the Federal Energy Regulatory Commission at *FERCOnlineSupport@ferc.gov* or call toll-free, (886) 208–3676 or TYY, (202) 502–8659.

Dated: November 30, 2022.

Kimberly D. Bose,

Secretary.

[FR Doc. 2022–26476 Filed 12–5–22; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CD23–3–000]

Oregon Department of Fish and Wildlife; Notice of Preliminary Determination of a Qualifying Conduit Hydropower Facility and Soliciting Comments and Motions To Intervene

On November 23, 2022, the Oregon Department of Fish and Wildlife, filed a notice of intent to construct a qualifying conduit hydropower facility, pursuant to section 30 of the Federal Power Act (FPA). The proposed Clackamas Fish Hatchery Hydroelectric Station Project would have an installed capacity of 175 kilowatts (kW), and would be located along a water supply pipeline at the applicant's fish hatchery in Estacada, Clackamas County, Oregon.

Applicant Contact: Andrew Benjamin, 403 Portway Avenue, Suite 300, Hood River, OR 97031, 530–420–6098, *abenjamin@nlineenergy.com.*

FERC Contact: Christopher Chaney, 202–502–6778, *christopher.chaney@ferc.gov.*

Qualifying Conduit Hydropower Facility Description: The project would consist of: (1) a 175-kW turbine generating unit to be installed within an existing building, (2) intake and discharge pipes connecting to the existing water supply pipeline, and (3) appurtenant facilities. The proposed project would have an estimated annual generation of approximately 1,000,000 kilowatt-hours.

A qualifying conduit hydropower facility is one that is determined or deemed to meet all the criteria shown in the table below.

TABLE 1—CRITERIA FOR QUALIFYING CONDUIT HYDROPOWER FACILITY

Statutory provision	Description	Satisfies (Y/N)
FPA 30(a)(3)(A)	The conduit the facility uses is a tunnel, canal, pipeline, aqueduct, flume, ditch, or similar manmade water conveyance that is operated for the distribution of water for agricultural, municipal, or industrial consumption and not primarily for the generation of electricity.	Y
FPA 30(a)(3)(C)(i)	The facility is constructed, operated, or maintained for the generation of electric power and uses for such generation only the hydroelectric potential of a non-federally owned conduit.	Y
FPA 30(a)(3)(C)(ii)	The facility has an installed capacity that does not exceed 40 megawatts	Y
FPA 30(a)(3)(C)(iii)	On or before August 9, 2013, the facility is not licensed, or exempted from the licensing requirements of Part I of the FPA.	Y

Preliminary Determination: The proposed Clackamas Fish Hatchery Hydroelectric Station Project will not alter the primary purpose of the conduit. Therefore, based upon the above criteria, Commission staff preliminarily determines that the operation of the project described above satisfies the requirements for a qualifying conduit hydropower facility, which is not required to be licensed or exempted from licensing.

Comments and Motions To Intervene: Deadline for filing comments contesting whether the facility meets the qualifying criteria is 30 days from the issuance date of this notice. Deadline for filing motions to intervene is 30 days from the issuance date of this notice.

Anyone may submit comments or a motion to intervene in accordance with the requirements of Rules of Practice and Procedure, 18 CFR 385.210 and 385.214. Any motions to intervene must be received on or before the specified deadline date for the particular proceeding.

Filing and Service of Responsive Documents: All filings must (1) bear in all capital letters the ''COMMENTS CONTESTING QUALIFICATION FOR A CONDUIT HYDROPOWER FACILITY'' or ''MOTION TO INTERVENE,'' as applicable; (2) state in the heading the name of the applicant and the project number of the application to which the filing responds; (3) state the name, address, and telephone number of the person filing; and (4) otherwise comply with the requirements of sections 385.2001 through 385.2005 of the Commission's regulations.[1] All comments contesting Commission staff's preliminary determination that the facility meets the qualifying criteria must set forth their evidentiary basis.

The Commission strongly encourages electronic filing. Please file motions to intervene and comments using the Commission's eFiling system at *http://www.ferc.gov/docs-filing/efiling.asp.* Commenters can submit brief comments up to 6,000 characters, without prior registration, using the eComment system at *http://www.ferc.gov/docs-filing/ecomment.asp.* You must include your name and contact information at the end of your comments. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov,* (866) 208–3676 (toll free), or (202) 502–8659 (TTY). In lieu of electronic filing, you may send a paper copy. 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. A copy of all other filings in reference to this application must be accompanied by proof of service on all persons listed in the service list prepared by the Commission in this proceeding, in accordance with 18 CFR 385.2010.

Locations of Notice of Intent: The Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's website at *http://www.ferc.gov/docs-filing/elibrary.asp.* Enter the docket number (*i.e.,* CD23–3) in the docket number field to access the document. You may also register online at *http://www.ferc.gov/docs-filing/esubscription.asp* to be notified via email of new filings and issuances related to this or other pending projects. Copies of the notice of intent can be obtained directly from the applicant. For assistance, call toll-free 1–866–208–3676 or email *FERCOnlineSupport@ferc.gov.* For TTY, call (202) 502–8659.

Dated: November 30, 2022.

Kimberly D. Bose,

Secretary.

[FR Doc. 2022–26473 Filed 12–5–22; 8:45 am]

BILLING CODE 6717–01–P

[1] 18 CFR 385.2001–2005 (2021).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER23–493–000]

Thunder Wolf Energy Center, LLC; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of Thunder Wolf Energy Center, LLC's application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is December 20, 2022.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically may mail similar pleadings to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426. Hand delivered submissions in docketed proceedings should be delivered to Health and Human Services, 12225 Wilkins Avenue, Rockville, Maryland 20852.

In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*http://www.ferc.gov*) using the ''eLibrary'' link. Enter the docket number excluding the last three digits in the docket number field to access the document. At this time, the Commission has suspended access to the Commission's Public Reference Room, due to the proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19), issued by the President on March 13, 2020. For assistance, contact the Federal Energy Regulatory Commission at *FERCOnlineSupport@ferc.gov* or call toll-free, (886) 208–3676 or TYY, (202) 502–8659.

Dated: November 30, 2022.

Kimberly D. Bose,

Secretary.

[FR Doc. 2022–26475 Filed 12–5–22; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. AD23–3–000]

Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements; Supplemental Notice of Staff-Led Workshop

As announced in the Notice of Staff-Led Workshop issued in this proceeding on October 6, 2022, Federal Energy Regulatory Commission (Commission) staff will convene a workshop to discuss whether and how the Commission could establish a minimum requirement for Interregional Transfer Capability for public utility transmission providers in transmission planning and cost allocation processes on December 5 and 6, 2022, from approximately 12:00 p.m. to 5:00 p.m. Eastern Time.

The purpose of this workshop is to consider the question of whether and how to establish a minimum requirement for Interregional Transfer

Capability. Topics for discussion may include: how to determine the need for and benefit of setting a minimum requirement for Interregional Transfer Capability; what to consider in establishing a potential Interregional Transfer Capability requirement, including who would be responsible for determining a minimum Interregional Transfer Capability requirement and what would be the objective and drivers of such a requirement; what process could be used in establishing a minimum Interregional Transfer Capability requirement to determine key data inputs, modeling techniques, and relevant metrics; and how costs for transmission facilities intended to increase Interregional Transfer Capability should be allocated and how to ensure a minimum amount of Interregional Transfer Capability is achieved and maintained.

While the workshop is not for the purpose of discussing any specific matters before the Commission, some workshop discussions may involve issues raised in proceedings that are currently pending before the Commission. These proceedings include, but are not limited to:

	Docket Nos.
Invenergy Transmission LLC	AD22–13–000.
Invenergy Transmission LLC v. Midcontinent Independent System Operator, Inc	EL22–83–000.
SOO Green HVDC Link ProjectCo, LLC v. PJM Interconnection, LLC	EL21–85–000, EL21–103–000.
PPL Electric Utilities Corporation, PJM Interconnection, L.L.C	ER22–2690–000, ER22–2690–001.
Appalachian Power Company, PJM Interconnection, L.L.C	ER19–2105–005.
Neptune Regional Transmission System, LLC and Long Island Power Authority v. PJM Interconnection, L.L.C.	EL21–39–000.
WestConnect Public Utilities	ER22–1105–000.
PPL Electric Utilities Corporation	ER22–1606–000.
Southwest Power Pool, Inc	ER22–1846–000.

Attached to this Supplemental Notice is an agenda for the workshop, which includes the workshop program and expected panelists.

Panelists are asked to submit advance materials to provide any information related to their respective panel (*e.g.,* summary statements, reports, whitepapers, studies, or testimonies) that panelists believe should be included in the record of this proceeding by November 21, 2022. Panelists should file all advance materials in the AD23–3–000 docket.

The workshop will take place virtually, with remote participation from both presenters and attendees. The workshop will be open to the public and there is no fee for attendance. Information will also be posted on the Calendar of Events on the Commission's website, *www.ferc.gov,* prior to the event.

The workshop will be transcribed and webcast. Transcripts will be available for a fee from Ace Reporting (202–347–3700). A free webcast of this event is available through the Commission's website. Anyone with internet access who desires to view this event can do so by navigating to *www.ferc.gov's* Calendar of Events and locating this event in the Calendar. The Federal Energy Regulatory Commission provides technical support for the free webcasts. Please call (202) 502–8680 or email *customer@ferc.gov* if you have any questions.

Commission workshops are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations, please send an email to *accessibility@ferc.gov,* call toll-free (866) 208–3372 (voice) or (202) 208–8659 (TTY), or send a fax to (202) 208–2106 with the required accommodations.

For more information about this workshop, please contact Jessica Cockrell at *jessica.cockrell@ferc.gov* or (202) 502–8190. For information related to logistics, please contact Sarah McKinley at *sarah.mckinley@ferc.gov* or (202) 502–8368.

Dated: November 30, 2022.

Kimberly D. Bose,

Secretary.

Staff-Led Workshop Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements, Docket No. AD23–3–000, December 5–6, 2022

Agenda and Speakers

Background

To aid in our discussion at the workshop, we will use the following terms:

- For this discussion, the definition of Interregional Transfer Capability is consistent with total transfer capability as defined in the Commission's regulations: ''the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions, or such definition as contained in Commission-approved Reliability Standards.'' 18 CFR 37.6(b)(1)(vi) (2021). In the context of Interregional Transfer Capability, an ''area'' in the above definition would be a transmission planning region composed of public utility transmission providers.
- For this discussion, Transfer Transmission Facility is defined as a transmission facility that increases the amount of electric power that can be moved or transferred reliably from one transmission planning region to another by way of all transmission lines (or paths) between those transmission planning regions. For purposes of geographic location, a Transfer Transmission Facility may be located entirely within a single transmission planning region (*i.e.,* either a local transmission facility or a regional transmission facility), or it may span two or more transmission planning regions (*i.e.,* an interregional transmission facility).

Day One: Monday, December 5, 2022

12:00 p.m.–12:10 p.m.: Welcome and Opening Remarks

12:10 p.m.–12:25 p.m.: Presentation from Dr. Dev Millstein, Research Scientist, Lawrence Berkeley National Lab, *Empirical Estimates of Transmission Value using Locational Marginal Prices*

12:25 p.m.–2:25 p.m.: Panel 1: Determining the Need for Additional Interregional Transfer Capability

This panel will explore whether the existing transmission planning and cost allocation and the interregional coordination and cost allocation processes adequately consider the need to establish a minimum requirement for Interregional Transfer Capability between neighboring transmission planning regions. In addition, the panel will discuss the specific drivers that may necessitate the establishment of a minimum requirement.

This panel may include a discussion of the following topics:

1. What are the current levels of Interregional Transfer Capability between transmission planning regions? Is more Interregional Transfer Capability between transmission planning regions needed? Why or why not?

2. Is the potential need for additional Interregional Transfer Capability currently considered in any transmission planning processes and if so, how? To the extent such needs are considered, have they resulted in the development of any transmission facilities?

3. What are the drivers of the need for increasing Interregional Transfer Capability? To what extent do these vary based on regional and system characteristics (*e.g.,* weather patterns, load diversity, resource mix, etc.)? Are there barriers to identifying or assessing these drivers?

4. Is a minimum amount of Interregional Transfer Capability between transmission planning regions necessary to ensure just and reasonable Commission-jurisdictional rates? If so, what evidence is there to support, or negate, that position? How will planning for a minimum amount of Interregional Transfer Capability produce just and reasonable rates?

5. Does the potential need for a minimum amount of Interregional Transfer Capability differ between RTO and non-RTO regions? Why or why not? Is a minimum amount of Interregional Transfer Capability necessary for non-RTO regions?

Panelists

- *Neil Millar*, Vice President, Infrastructure and Operations Planning, California Independent System Operator Corporation
- *Liza Reed, Ph.D.*, Research Manager, Electricity Transmission, Niskanen Center
- *Michele Kito*, Supervisor, Electric Market Design Section, California Public Utilities Commission
- *Philip D. Moeller*, Executive Vice President, Edison Electric Institute
- *Tricia Pridemore*, Chairman, Georgia Public Service Commission
- *Simon Mahan*, Executive Director, Southern Renewable Energy Association

2:25 p.m.–2:45 p.m.: Break

2:45 p.m.–3:00 p.m.: Presentation from Dr. Adria Brooks, U.S. Department of Energy Grid Deployment Office, Transmission Division

3:00 p.m.–4:55 p.m.: Panel 2: Considerations for Establishing Potential Interregional Transfer Capability Requirements

This panel will discuss who would be responsible for determining a minimum Interregional Transfer Capability requirement and the relevant considerations for establishing such a requirement, assuming that there is such a need. Specifically, this panel will focus on identifying the objective, and drivers, of a minimum Interregional Transfer Capability requirement. This panel may include a discussion of the following topics:

1. What principles should be used to establish a minimum amount of Interregional Transfer Capability (*e.g.,* should a minimum Interregional Transfer Capability requirement be determined based on the cost impact to transmission customers during extreme events, such as extreme weather, wide-spread loss of fuel supply, etc.)?

2. To what extent, if any, should the following be considered when establishing a minimum Interregional Transfer Capability requirement?

a. Historical or projected extreme events (*e.g.,* extreme weather, loss of fuel supply, etc.)

b. Load and resource diversity across a wide geographic area

c. Anticipated changes in the resource mix and demand

d. Improved reliability

e. Avoided production costs

f. Geographic zones with the potential for large amounts of new generation

g. The option value of Transfer Transmission Facilities, as determined by the increased access to supplemental capacity during emergency operating conditions.

h. Increased operator flexibility

i. Others?

3. Should planning criteria other than reliability and resilience be considered in establishing a minimum Interregional Transfer Capability requirement?

4. For this question, please consider: (a) public utility transmission providers in each pair of neighboring transmission planning regions, (b) the public utility transmission providers in all of a transmission planning region's neighboring transmission planning regions, and (c) all public utility transmission providers within an Interconnection.

a. What role should the Commission, relevant groupings of public utility transmission providers described in (a), (b), and (c) above, or other relevant entities play in determining what, if any, minimum amount of Interregional Transfer Capability is needed? What are the advantages and disadvantages of each approach?

b. Should the Commission establish a specific formula or planning process, or instead more general criteria, guidelines, or principles for public utility transmission providers to follow in establishing a minimum Interregional Transfer Capability? Should the Commission allow public utility transmission providers flexibility in whether to work on a bilateral basis with neighboring regions, or require planning to be carried out across a broader geography? What are the advantages and disadvantages of each approach?

c. Should the principles considered be consistent for (a), (b) or (c) above? What are the advantages and disadvantages of each approach?

5. How should merchant transmission facility developers and public utility transmission providers conducting transmission planning avoid planning duplicative or conflicting transmission facilities to increase Interregional Transfer Capability?

6. To what extent, if at all, would a minimum Interregional Transfer Capability requirement complement or conflict with a potential new or modified NERC Reliability Standard that requires consideration of extreme heat and cold events as proposed in Docket No. RM22–10?

7. Should the establishment of a minimum amount of Interregional Transfer Capability for non-RTO regions differ from that for RTO regions? If so, how?

Panelists

- *Debra Lew, Ph.D.*, Associate Director, Energy System Integration Group
- *Aaron Bloom*, Executive Director, NextEra Energy Transmission, LLC
- *Laura Rauch*, Senior Director, Transmission Planning, Midcontinent Independent System Operator, Inc.
- *David Kelley*, Director of Seams and Tariff Services, Southwest Power Pool, Inc.
- *Saad Malik*, Director Reliability Planning, Western Electricity Coordinating Council
- *Deral Danis*, Senior Director, Transmission, Pattern Energy Group LP
- *Sharon Segner*, Senior Vice President of Transmission Policy, LS Power Development, LLC

4:55 p.m.–5:00 p.m.: Closing Remarks

Day Two: Tuesday, December 6, 2022

12:00 p.m.–12:10 p.m.: Welcome and Opening Remarks

12:10 p.m.–2:15 p.m.: Panel 3: Process for Establishing Potential Interregional Transfer Capability Requirements

This panel will discuss the process for determining a minimum amount of Interregional Transfer Capability including, but not limited to, the determination of key data inputs, modeling techniques, and relevant metrics.

This panel may include a discussion of the following topics:

1. What process should be used to determine a minimum amount of Interregional Transfer Capability? For example, should the minimum be (a) derived heuristically from past extreme events; (b) derived using a probabilistic approach; or (c) based on scenario planning similar to the requirements proposed for Long-Term Regional Transmission Planning (Docket No. RM21–17–000) or other deterministic analysis? What are the advantages and disadvantages of each approach?

a. With respect to a probabilistic approach, what are the primary challenges in developing probabilistic models to determine a minimum amount of Interregional Transfer Capability? Do current probabilistic methods model common mode outages appropriately? If not, to what extent does that reduce the usefulness of a probabilistic approach?

b. With respect to scenario planning to determine a minimum amount of Interregional Transfer Capability, what guidelines, if any, are necessary to ensure that such scenario planning adequately assesses the need for, and value of, increased Interregional Transfer Capability? Are certain types of scenarios particularly important to assess the need for, and value of, Interregional Transfer Capability? Should scenario planning account for wide-area events and correlated outages, and if so, how?

2. After a need for a minimum amount of Interregional Transfer Capability is determined, what models and data are necessary to evaluate it? Do public utility transmission providers typically have access to or collect these models and data? If not, how should public utility transmission providers acquire these models and data? To simulate the wide-area impact of extreme events, to what extent should these models and data represent the overall interconnection?

3. What criteria should be used to assess whether public utility transmission providers have sufficient existing transmission facilities to meet or surpass an Interregional Transfer Capability requirement? Please specify whether your answer to this question depends on your answer to question 1 in this panel.

a. Is there a benefit to using a specific metric of Interregional Transfer Capability? Potential metrics may include a set amount of electric power, an amount of electric power relative to some electric power characteristic of the transmission planning region (like peak load, or the largest single contingency), among others.

b. To what extent should public utility transmission providers in a transmission planning region consider criteria that would help ensure the ''right amount'' of Interregional Transfer Capability is identified and sufficient Transfer Transmission Facilities are selected to meet an Interregional Transfer Capability requirement? For example, should the criteria used to assess whether public utility transmission providers meet an Interregional Transfer Capability requirement be informed by the net-benefits, or other types of measures, of Transfer Transmission Facilities?

4. What operational barriers preclude potential Interregional Transfer Capability from being realized during normal and emergency system conditions?

Panelists

- *Sheila Manz, Ph.D.*, Technical Director, Decarbonization Planning, GE Energy Consulting
- *Digaunto Chatterjee*, Vice President, System Planning, Eversource Energy
- *David Souder*, Executive Director, System Planning, PJM Interconnection, L.L.C. and Vice Chair, Eastern Interconnection Planning Collaborative Technical Committee
- *Michael Goggin*, Vice President, Grid Strategies, LLC, speaking on behalf of the American Clean Power Association
- *Nicolas Koehler*, Director, Transmission Planning, American Electric Power Company
- *Christopher Clack, Ph.D.*, Chief Executive Officer, Vibrant Clean Energy, LLC

2:15 p.m.–2:30 p.m.: Break

2:30 p.m.–4:45 p.m.: Panel 4: Meeting the Goal of Increased Interregional Transfer Capability

This panel will discuss how costs for Transfer Transmission Facilities should be allocated and how to ensure a minimum amount of Interregional Transfer Capability is achieved and maintained.

This panel may include a discussion of the following topics:

1. How should cost allocation for Transfer Transmission Facilities be determined? For example, should public utility transmission providers in a transmission planning region be required to allocate the costs of Transfer Transmission Facilities: (1) within their own transmission planning region; (2) jointly with two or more neighboring transmission planning regions; (3) at an Interconnection-wide level; or (4) via some other process? What are the advantages or disadvantages of each approach? Should there be a process in place for the Commission to establish a cost allocation method for Transfer Transmission Facilities if the public utility transmission providers in (1), (2), or (3) above cannot agree?

a. How should the process for evaluating, selecting, and allocating the costs of Transfer Transmission Facilities align with current regional transmission planning and interregional transmission coordination processes (*e.g.,* should the process be a part of existing transmission planning and cost allocation and/or coordination and cost allocation processes or should it be a separate process)?

2. How would public utility transmission providers in a transmission planning region demonstrate that they have met the minimum Interregional Transfer Capability requirement?

3. What process would public utility transmission providers in (a) a transmission planning region, (b) a pair of transmission planning regions, or (c) a broader collection of neighboring planning regions use to identify and select Transfer Transmission Facilities?

4. Should the Commission reexamine the minimum Interregional Transfer Capability requirement or the required process to identify and select Transfer Transmission Facilities at some point in the future (*e.g.,* in 10 years)?

5. What, if any, categories of benefits should public utility transmission providers be required to consider when evaluating Transfer Transmission Facilities for selection for purposes of cost allocation?

a. Should the benefits considered be consistent between (a) public utility transmission providers in each pair of neighboring transmission planning regions, (b) the public utility transmission providers in all of a transmission planning region's neighboring transmission planning regions, or (c) all public utility transmission providers within an Interconnection? What are the advantages and disadvantages of each approach?

6. Should the Commission prescribe a standard, or principles to govern the selection of Transfer Transmission Facilities for purposes of cost allocation?

7. Should the Commission require public utility transmission providers to use a portfolio approach for selecting Transfer Transmission Facilities to meet a minimum amount of Interregional Transfer Capability?

8. What rules, if any, should the Commission promulgate with regard to establishing a cost allocation method for Transfer Transmission Facilities?

a. What are the advantages and disadvantages of the Commission requiring a specific *ex ante* regional and/or interregional cost allocation method for Transfer Transmission Facilities?

b. What are the advantages and disadvantages of the Commission requiring a specific *ex post* regional and/or interregional cost allocation method or a hybrid (*i.e.,* part *ex ante* and part *ex post*) for Transfer Transmission Facilities?

c. Should the Commission decline to prescribe an *ex ante* or *ex post* cost allocation method for applicable public utility transmission providers, what process should govern the establishment of cost allocation rules for any particular Transfer Transmission Facility?

9. What role should state and local governmental entities play in the public utility transmission provider process for selection and cost allocation for Transfer Transmission Facilities? Should the states' role in selection and cost allocation be determined by the drivers of the need for a minimum requirement for Transfer Transmission Facilities? For example, if the Transfer Transmission Facilities are planned to serve public policy goals, such as renewable generation deployment, should the states have a role in cost allocation, such as that proposed in the Notice of Proposed Rulemaking in RM21–17?

10. Are there barriers to the ability of interregional merchant transmission facilities in providing a minimum amount of Interregional Transfer Capability? For example, do contractual or tariff limitations prevent merchant interregional high-voltage direct current transmission facilities from supporting reliability during extreme events?

Panelists

- *Kris Zadlo*, Chief Development Officer, Grid United
- *Travis Kavulla*, Vice President Regulatory Affairs, NRG Energy, Inc.
- *Shashank Sane*, Executive Vice President, Transmission, Invenergy
- *Rob Gramlich*, Founder and President, Grid Strategies, LLC
- *Andrew French*, Commissioner, Kansas Corporation Commission
- *J. Arnold Quinn*, Chief Economist, Vistra Corp.

4:45 p.m.–5:00 p.m.: Closing Remarks

[FR Doc. 2022–26474 Filed 12–5–22; 8:45 am]

BILLING CODE 6717–01–P

FEDERAL DEPOSIT INSURANCE CORPORATION

Notice of Termination of Receiverships

The Federal Deposit Insurance Corporation (FDIC or Receiver), as Receiver for each of the following insured depository institutions, was charged with the duty of winding up the affairs of the former institutions and liquidating all related assets. The Receiver has fulfilled its obligations and made all dividend distributions required by law.

NOTICE OF TERMINATION OF RECEIVERSHIPS

Fund	Receivership name	City	State	Termination date
10005	ANB Financial, NA	Bentonville	AR	12/01/2022
10012	Integrity Bank	Alpharetta	GA	12/01/2022
10037	Corn Belt Bank & Trust Company	Pittsfield	IL	12/01/2022
10061	Bankunited, FSB	Coral Gables	FL	12/01/2022
10131	Hillcrest Bank Florida	Naples	FL	12/01/2022
10220	Citizens Bank & Trust Company of Chicago	Chicago	IL	12/01/2022
10330	The Bank of Asheville	Asheville	NC	12/01/2022
10336	American Trust Bank	Roswell	GA	12/01/2022
10531	THE Enloe State Bank	Cooper	TX	12/01/2022

The Receiver has further irrevocably authorized and appointed FDIC-Corporate as its attorney-in-fact to execute and file any and all documents that may be required to be executed by the Receiver which FDIC-Corporate, in its sole discretion, deems necessary, including but not limited to releases, discharges, satisfactions, endorsements, assignments, and deeds. Effective on the termination dates listed above, the Receiverships have been terminated, the Receiver has been discharged, and the Receiverships have ceased to exist as legal entities.

(*Authority:* 12 U.S.C. 1819)

Federal Deposit Insurance Corporation.

Dated at Washington, DC, on December 1, 2022.

James P. Sheesley,

Assistant Executive Secretary.

[FR Doc. 2022–26505 Filed 12–5–22; 8:45 am]

BILLING CODE 6714–01–P

FEDERAL HOUSING FINANCE AGENCY

[No. 2022–N–15]

Proposed Collection; Comment Request

AGENCY: Federal Housing Finance Agency.

ACTION: 60-Day notice of submission of information collection for approval from Office of Management and Budget.

SUMMARY: In accordance with the requirements of the Paperwork Reduction Act of 1995 (PRA), the Federal Housing Finance Agency (FHFA) is seeking public comments concerning an information collection known as the ''National Survey of Mortgage Originations'' (NSMO), which has been assigned control number 2590–0012 by the Office of Management and Budget (OMB). FHFA intends to submit the information collection to OMB for review and approval of a three-year extension of the control number, which is due to expire on June 30, 2023.

DATES: Interested persons may submit comments on or before February 6, 2023.

ADDRESSES: Submit comments to FHFA, identified by ''Proposed Collection; Comment Request: 'National Survey of Mortgage Originations, (No. 2022–N–15)' '' by any of the following methods:

• *Agency website: www.fhfa.gov/open-for-comment-or-input.*

• *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments. If you submit your comment to the *Federal eRulemaking Portal,* please also send it by *email* to FHFA at *RegComments@fhfa.gov* to ensure timely receipt by the agency.

• *Mail/Hand Delivery:* Federal Housing Finance Agency, Fourth Floor, 400 Seventh Street SW, Washington, DC 20219, ATTENTION: Proposed Collection; Comment Request: ''National Survey of Mortgage Originations, (No. 2022–N–15).''

We will post all public comments we receive without change, including any personal information you provide, such as your name and address, email address, and telephone number, on the FHFA website at *http://www.fhfa.gov.* In addition, copies of all comments received will be available for examination by the public through the electronic comment docket for this PRA Notice also located on the FHFA website.

FOR FURTHER INFORMATION CONTACT: Saty Patrabansh, Associate Director, Office of Data and Statistics, *Saty.Patrabansh@fhfa.gov,* (202) 649–3213; or Angela Supervielle, Counsel, by email at *Angela.Supervielle@fhfa.gov,* by telephone at (202) 649–3973, (these are not toll-free numbers), Federal Housing Finance Agency, 400 Seventh Street SW, Washington, DC 20219. For TTY/TRS users with hearing and speech disabilities, dial 711 and ask to be connected to any of the contact numbers above.

SUPPLEMENTARY INFORMATION:

A. Need For and Use of the Information Collection

The NSMO is a recurring quarterly survey of individuals who have recently obtained a loan secured by a first mortgage on single-family residential property. The survey questionnaire is sent to a representative sample of approximately 6,000 recent mortgage borrowers each calendar quarter and typically consists of about 96 multiple choice and short answer questions designed to obtain information about borrowers' experiences in choosing and in taking out a mortgage.[1] The questionnaire may be completed either on paper (in English only) or electronically online (in either English or Spanish). FHFA is also seeking clearance to pretest future iterations of the survey questionnaire and related materials from time to time through the use of cognitive pre-testing. A copy of the survey questionnaire sent out in the fourth quarter of 2022 appears at the end of this notice.[2]

The NSMO is a component of the ''National Mortgage Database'' (NMDB) Program which is a joint effort of FHFA and the Consumer Financial Protection Bureau (CFPB). The NMDB Program is designed to satisfy the Congressionally-mandated requirements of section 1324(c) of the Federal Housing Enterprises Financial Safety and Soundness Act.[3] Section 1324(c) requires that FHFA conduct a monthly survey to collect data on the characteristics of individual prime and subprime mortgages, and on the borrowers and properties associated with those mortgages, in order to enable it to prepare a detailed annual report on the mortgage market activities of the Federal National Mortgage Association (Fannie Mae) and the Federal Home Loan Mortgage Corporation (Freddie Mac) for review by the appropriate Congressional oversight committees. Section 1324(c) also authorizes and requires FHFA to compile a database of otherwise unavailable residential mortgage market information and to make that information available to the public in a timely fashion.

As a means of fulfilling those and other statutory requirements, as well as to support policymaking and research regarding the residential mortgage markets, FHFA and CFPB jointly established the NMDB Program in 2012. The Program is designed to provide comprehensive information about the U.S. mortgage market and has three primary components: (1) the NMDB; (2) the NSMO; and (3) the American Survey of Mortgage Borrowers (ASMB).

The NMDB is a de-identified loan-level database of closed-end first-lien residential mortgage loans that is representative of the market as a whole, contains detailed loan-level information on the terms and performance of the mortgages and the characteristics of the associated borrowers and properties, is continually updated, has an historical component dating back to 1998, and provides a sampling frame for surveys to collect additional information. The core data in the NMDB are drawn from a random 1-in-20 sample of all closed-end first-lien mortgage files outstanding at any time between January 1998 and the present in the files of Experian, one of the three national credit repositories, with a random sample of mortgages newly reported to Experian added each quarter.

The NMDB draws additional information on mortgages in the NMDB datasets from other existing sources, including the Home Mortgage Disclosure Act (HMDA) data that are maintained by the Federal Financial Institutions Examination Council (FFIEC), property valuation models, and administrative data files maintained by Fannie Mae and Freddie Mac and by federal agencies. FHFA also obtains data from the ASMB, which historically solicited information on borrowers' experience with maintaining their existing mortgages, including their experience maintaining mortgages under financial stress, their experience in soliciting financial assistance, their success in accessing federally-sponsored programs designed to assist them, and, where applicable, any challenges they may have had in terminating a mortgage loan.[4]

While the ASMB focused on borrowers' experience with maintaining existing mortgages, the NSMO solicits information on newly-originated mortgages and the borrowers' experiences with the mortgage origination process. It was developed to complement the NMDB by providing critical and timely information—not available from existing sources—on the range of nontraditional and subprime mortgage products being offered, the methods by which these mortgages are being marketed, and the characteristics of borrowers for these types of loans. In particular, the survey questionnaire is designed to elicit directly from mortgage borrowers information on the characteristics of the borrowers and on their experiences in finding and obtaining a mortgage loan, including: their mortgage shopping behavior; their mortgage closing experiences; their expectations regarding house price appreciation; and critical financial and other life events affecting their households, such as unemployment, expenses or divorce. The survey questions do not focus on the terms of the borrowers' mortgage loans because these fields are available in the Experian

[1] The NSMO questionnaire sent out in the fourth quarter of 2022 contained 96 questions.

[2] In addition, a copy of the questionnaire can be accessed online at: *http://www.fhfa.gov/Homeownersbuyer/Pages/National-Survey-of-Mortgage-Originations.aspx.*

[3] 12 U.S.C. 4544(c).

[4] OMB has assigned the ASMB control no. 2590–0015, which expires on July 31, 2025.

data. However, the NSMO collects a limited amount of information on each respondent's mortgage to verify that the Experian records and survey responses pertain to the same mortgage.

Each wave of the NSMO is sent to the primary borrowers on about 6,000 mortgage loans, which are drawn from a simple random sample of the 80,000 to 100,000 newly originated mortgage loans that are added to the National Mortgage Database from the Experian files each quarter (at present, this represents an approximately 1-in-15 sample of loans added to the National Mortgage Database and an approximately 1-in-300 sample of all mortgage loan originations). By contract with FHFA, the conduct of the NSMO is administered through Experian, which has subcontracted the survey administration through a competitive process to Westat, a nationally-recognized survey vendor.[5] Westat also carries out the pre-testing of the survey materials.

B. Need For and Use of the Information Collection

FHFA views the NMDB Program as a whole, including the NSMO, as the monthly ''survey'' that is required by section 1324 of the Safety and Soundness Act. Core inputs to the NMDB, such as a regular refresh of the Experian data, occur monthly, though NSMO itself does not. In combination with the other information in the NMDB, the information obtained through the NSMO is used to prepare the report to Congress on the mortgage market activities of Fannie Mae and Freddie Mac that FHFA is required to submit under section 1324, as well as for research and analysis by FHFA and CFPB in support of their regulatory and supervisory responsibilities related to the residential mortgage markets. The NSMO is especially critical in ensuring that the NMDB contains uniquely comprehensive information on the range of nontraditional and subprime mortgage products being offered, the methods by which these mortgages are being marketed and the characteristics—and particularly the creditworthiness—of borrowers for these types of loans. In July 2021, FHFA and the CFPB released a loan-level dataset collected through the NSMO for public use.[6] The information provides a resource for research and analysis by federal agencies, by Fannie Mae and Freddie Mac, and by academics and other interested parties outside of the government.

FHFA is also seeking OMB approval to continue to conduct cognitive pre-testing of the survey materials. The Agency uses information collected through that process to assist in drafting and modifying the survey questions and instructions, as well as the related communications, to read in the way that will be most readily understood by the survey respondents and that will be most likely to elicit usable responses. Such information is also used to help the Agency decide on how best to organize and format the survey questionnaires.

The OMB control number for this information collection is 2590–0012. The current clearance for the information collection expires on June 30, 2023.

C. Burden Estimate

FHFA has analyzed the hour burden on members of the public associated with conducting the survey (10,080 hours) and with pre-testing the survey materials (50 hours) and estimates the total annual hour burden imposed on the public by this information collection to be 10,130 hours. The estimate for each phase of the collection was calculated as follows:

I. Conducting the Survey

FHFA estimates that the NSMO questionnaire will be sent to 24,000 recipients annually (6,000 recipients per quarterly survey × 4 calendar quarters). Although, based on historical experience, the Agency expects that only 20 to 30 percent of those surveys will be returned, it has assumed that all of the surveys will be returned for purposes of this burden calculation. Based on the reported experience of respondents to prior NSMO questionnaires, FHFA estimates that it will take each respondent 25 minutes to complete the survey, including the gathering of necessary materials to respond to the questions. This results in a total annual burden estimate of 10,080 hours for the survey phase of this collection (24,000 respondents × 25 minutes per respondent = 10,080 hours annually).

II. Pre-Testing the Materials

FHFA estimates that it will pre-test the survey materials with 50 cognitive testing participants annually. The estimated participation time for each participant is one hour, resulting in a total annual burden estimate of 50 hours for the pre-testing phase of the collection (50 participants × 1 hour per participant = 50 hours annually).

D. Comment Request

FHFA requests written comments on the following: (1) Whether the collection of information is necessary for the proper performance of FHFA functions, including whether the information has practical utility; (2) the accuracy of FHFA's estimates of the burdens of the collection of information; (3) ways to enhance the quality, utility, and clarity of the information collected; and (4) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

Shawn Bucholtz,

Chief Data Officer, Federal Housing Finance Agency.

BILLING CODE 8070–01–P

[5] The Fair Credit Reporting Act, 15 U.S.C. 1681 *et seq.,* requires that the survey process, because it utilizes borrower names and addresses drawn from credit reporting agency records, must be administered through Experian in order to maintain consumer privacy.

[6] The July 2021 NSMO public use dataset can be accessed here: *https://www.fhfa.gov/DataTools/Downloads/Pages/NMDB_Data_Sets.aspx.*

FEDERAL HOUSING FINANCE AGENCY FHFA

cfpb Consumer Financial Protection Bureau

Improving Mortgage Experiences in America

National Survey of Mortgage Originations

You have been selected to participate in an important national survey. Learning directly from borrowers like you about your experiences obtaining a mortgage to purchase or refinance your home will help us improve lending practices and the mortgage process for future borrowers like you.

To Complete the Survey Online

PC/TABLET	Go to: www.NSMOsurvey.com and enter the unique access code provided in the letter and your 5-digit zip code.
MOBILE DEVICE	Text your unique access code to (202) 759-2029 to receive a link to the survey or scan the QR code.
ESPAÑOL	Vaya a: www.NSMOsurvey.com e ingrese el código de acceso único que se le envió en la carta y su código postal de 5 digitos.
	Para contestar la encuesta en un aparato móvil/teléfono inteligente Envie en un mensaje de texto su código de acceso único al (202) 759-2029 o escanee el código QR.

While we prefer online to help us save costs for processing, it is important we hear from you. If you prefer paper, you can mail back the completed survey in the enclosed pre-paid postage envelope.

If you have any questions about the survey or taking the survey online, please call 1-855-339-7877
For more information visit our websites – www.fhfa.gov/nsmo and consumerfinance.gov

National Survey of Mortgage Originations

Who is sponsoring this survey?

The **Federal Housing Finance Agency (FHFA),** is an independent regulatory agency responsible for the effective supervision, regulation, and housing mission oversight of **Fannie Mae, Freddie Mac,** the Federal Home Loan Bank System, and the Office of Finance, and ensures a competitive, liquid, efficient, and resilient housing finance market.

The **Consumer Financial Protection Bureau (CFPB)** is a Federal agency created in 2010 to make mortgages, credit cards, automobile and other consumer loans work better and ensure that these markets are fair, transparent, and competitive.

How was I selected for this survey?

Survey recipients were selected at random from across the United States. Your answers will not be connected to your name or any other identifying information.

How long will it take?

The time will vary based on your experiences, but you can expect to spend 15-25 minutes.

Privacy Act Notice: In accordance with the Privacy Act, as amended (5 U.S.C. § 552a), the following notice is provided. The information requested on this Survey is collected pursuant to 12 U.S.C. 4544 for the purposes of gathering information for the National Mortgage Database. Routine uses which may be made of the collected information can be found in the Federal Housing Finance Agency's System of Records Notice (SORN) FHFA-21 National Mortgage Database. Providing the requested information is voluntary. Submission of the survey authorizes FHFA to collect the information provided and to disclose it as set forth in the referenced SORN.

Paperwork Reduction Act Statement: Notwithstanding any other provision of the law, no person is required to respond to, nor shall any person be subject to a penalty for failure to comply with, a collection of information subject to the requirements of the Paperwork Reduction Act, unless that collection of information displays a currently valid OMB Control Number.

OMB No. 2590-0012
Expires 6/30/23

1. Did you take out or co-sign for a mortgage loan sometime in the last couple of years including a purchase or any refinance/modification of an existing loan?

☐ Yes
☐ No → **Skip to 71 on page 7**

2. When did you take out this mortgage? If you took out or co-signed for more than one mortgage, please refer to your experience with the most recent refinance, modification, or new mortgage.

_____ / _____
month year

3. Did we mail this survey to the address of the property you financed with this mortgage?

☐ Yes ☐ No

4. Who signed or co-signed for this mortgage? *Mark all that apply.*

☐ I signed
☐ Spouse/partner including a former spouse/partner
☐ Parents
☐ Children
☐ Other relatives
☐ Other (e.g. friend, business partner)

→ If you co-signed this loan with others, take into account all co-signers as best you can when answering the survey. If no co-signers, answer based on your own situation.

5. When you began the process of getting this mortgage, how familiar were you (and any co-signers) with each of the following?

	Very	Somewhat	Not At All
The mortgage interest rates available at that time	☐	☐	☐
The different types of mortgages available	☐	☐	☐
The mortgage process	☐	☐	☐
The down payment needed to qualify for a mortgage	☐	☐	☐
The income needed to qualify for a mortgage	☐	☐	☐
Your credit history or credit score	☐	☐	☐
The money needed at closing	☐	☐	☐

6. When you began the process of getting this mortgage, how concerned were you about qualifying for a mortgage?

☐ Very ☐ Somewhat ☐ Not at all

7. How firm an idea did you have about the mortgage you wanted?

☐ Firm idea ☐ Some idea ☐ Little idea

8. How much did you use each of the following sources to get information about mortgages or mortgage lenders?

	A Lot	A Little	Not At All
Your mortgage lender/broker	☐	☐	☐
Other mortgage lenders/brokers	☐	☐	☐
Real estate agents or builders	☐	☐	☐
Material in the mail	☐	☐	☐
Websites that provide information on getting a mortgage	☐	☐	☐
Newspaper/TV/Radio	☐	☐	☐
Friends/relatives/co-workers	☐	☐	☐
Bankers, credit unions or financial planners	☐	☐	☐
Housing counselors	☐	☐	☐
Other (specify) ________	☐	☐	☐

9. Which one of the following best describes your shopping process?

☐ I picked the loan type first, and then I picked the mortgage lender/broker
☐ I picked the mortgage lender/broker first, and then I picked the loan type

10. Which one of the following best describes how you applied for this mortgage?

☐ Directly to a lender, such as a bank or credit union
☐ Through a mortgage broker who works with multiple lenders to get you a loan
☐ Through a builder who arranged financing
☐ Other (specify) ________

11. How many different mortgage lenders/brokers did you seriously consider before choosing where to apply for this mortgage?

☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 or more

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12. How many different mortgage lenders/brokers did you end up applying to?

☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 or more

13. Did you apply to more than one mortgage lender/broker for any of the following reasons?

	Yes	No
Searching for better loan terms	☐	☐
Concern over qualifying for a loan	☐	☐
Information learned from the "Loan Estimate"	☐	☐
Turned down on earlier application	☐	☐

14. How important were each of the following in choosing the mortgage lender/broker you used for the mortgage you took out?

	Important	Not Important
Having an established banking relationship	☐	☐
Having a local office or branch nearby	☐	☐
Used previously to get a mortgage	☐	☐
Mortgage lender/broker is a personal friend or relative	☐	☐
Paperless online mortgage process	☐	☐
Recommendation from a friend/ relative/co-worker	☐	☐
Recommendation from a real estate agent/home builder	☐	☐
Reputation of mortgage lender/broker	☐	☐
Spoke my primary language, which is not English	☐	☐
Accommodations for people with disabilities	☐	☐

15. Who initiated the first contact between you and the mortgage lender/broker you used for the mortgage you took out?

☐ I (or one of my co-signers) did
☐ The mortgage lender/broker did
☐ We were put in contact by a third party *(such as a real estate agent or home builder)*

16. While you were getting your mortgage, how did you primarily interact with your mortgage lender/broker?

☐ Online (web portal, email)
☐ Phone (voice calls, text messages, fax)
☐ Mail
☐ In person
☐ No primary way

17. How open were you to suggestions from your mortgage lender/broker about mortgages with different features or terms?

☐ Very ☐ Somewhat ☐ Not at all

18. How important were each of the following in determining the mortgage you took out?

	Important	Not Important
Lower interest rate	☐	☐
Lower APR *(Annual Percentage Rate)*	☐	☐
Lower closing fees	☐	☐
Lower down payment	☐	☐
Lower monthly payment	☐	☐
An interest rate fixed for the life of the loan	☐	☐
A term of 30 years	☐	☐
No mortgage insurance	☐	☐

19. Your lender may have given you a booklet "Your home loan toolkit: A step-by-step guide," do you remember receiving a copy?

☐ Yes
☐ No
☐ Don't know

20. In the process of getting this mortgage from your mortgage lender/broker, did you…

	Yes	No
Have to add another co-signer to qualify	☐	☐
Resolve credit report errors or problems	☐	☐
Answer follow-up requests for more information about income or assets	☐	☐
Have more than one appraisal	☐	☐
Redo/refile paperwork due to processing delays	☐	☐
Delay or postpone closing date	☐	☐
Have your "Loan Estimate" revised to reflect changes in your loan terms	☐	☐
Check other sources to confirm that terms of this mortgage were reasonable	☐	☐

21. Did the "Loan Estimate" you received from your mortgage lender/broker…

	Yes	No
Have easy to understand information	☐	☐
Contain valuable information	☐	☐
Cause you to take an action, such as seek a change in your loan or closing	☐	☐

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22. **During the application process were you told about mortgages with any of the following?**

	Yes	No
An interest rate that is fixed for the life of the loan	☐	☐
An interest rate that could change over the life of the loan	☐	☐
A term of less than 30 years	☐	☐
A higher interest rate in return for lower closing costs	☐	☐
A lower interest rate in return for paying higher closing costs *(discount points)*	☐	☐
Interest-only monthly payments	☐	☐
An escrow account for taxes and/or homeowner insurance	☐	☐
A prepayment penalty *(fee if the mortgage is paid off early)*	☐	☐
Reduced documentation or "easy" approval	☐	☐
An FHA, VA, USDA or Rural Housing loan	☐	☐

23. **In selecting your settlement/closing agent did you use someone…**

	Yes	No
Selected/recommended by the mortgage lender/broker, or real estate agent	☐	☐
You used previously	☐	☐
Found shopping around	☐	☐

☐ Did not have a settlement/closing agent

24. **Do you have title insurance on this mortgage?**

☐ Yes
☐ No
☐ Don't know } Skip to 26

25. **Which one best describes how you picked the title insurance?**

☐ Reissued previous title insurance
☐ Used title insurance recommended by mortgage lender/broker or settlement agent
☐ Shopped around

26. **Overall, how satisfied are you that the mortgage you got was the one with the...**

	Very	Somewhat	Not At All
Best terms to fit your needs	☐	☐	☐
Lowest interest rate for which you could qualify	☐	☐	☐
Lowest closing costs	☐	☐	☐

27. **Overall, how satisfied are you with the…**

	Very	Somewhat	Not At All
Mortgage lender/broker you used	☐	☐	☐
Application process	☐	☐	☐
Documentation process required for the loan	☐	☐	☐
Property appraisal	☐	☐	☐
Loan closing process	☐	☐	☐
Information in mortgage disclosure documents	☐	☐	☐
Timeliness of mortgage disclosure documents	☐	☐	☐
Settlement agent	☐	☐	☐

28. **Did you take a course about home-buying or talk to a professional housing counselor?**

☐ Yes
☐ No → **Skip to 32 on page 4**

29. **Was your home-buying course or counseling...**

	Yes	No
In person, one-on-one	☐	☐
In person, in a group	☐	☐
Over the phone	☐	☐
Online	☐	☐
Required	☐	☐

30. **How many hours was your home-buying course or counseling?**

☐ Less than 3 hours
☐ 3 – 6 hours
☐ 7 – 12 hours
☐ More than 12 hours

31. **Overall, how helpful was your home-buying course or counseling?**

☐ Very ☐ Somewhat ☐ Not at all

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32. Which one of these reasons best describes this most recent mortgage?

- ☐ To buy a property
- ☐ To refinance or modify an earlier mortgage
- ☐ To add/remove co-signer(s)/co-owner(s)
- ☐ To finance a construction loan
- ☐ To take out a new loan on a mortgage-free property
- ☐ Some other purpose (specify) ______

Skip to 36

33. Did you do the following before or after you made an offer on this house or property?

	Before Offer	After Offer	Did Not Do
Contacted a lender to explore mortgage options	☐	☐	☐
Got a pre-approval or pre-qualification from a lender	☐	☐	☐
Decided on the type of loan	☐	☐	☐
Made a decision on which lender to use	☐	☐	☐
Submitted an official loan application	☐	☐	☐

34. Did you use any of the following sources of funds to buy this property?

	Used	Not Used
Proceeds from the sale of another property	☐	☐
Savings, retirement account, inheritance, or other assets	☐	☐
Assistance or loan from a nonprofit or government agency	☐	☐
A second lien, home equity loan, or home equity line of credit (HELOC)	☐	☐
Gift or loan from family or friend	☐	☐
Seller contribution	☐	☐

35. What percent of the purchase price was the down payment to buy this property (including money from a prior home sale, gifts, etc.)?

______ % ☐ Don't know

Skip to 39

36. How important were the following in your decision to refinance, modify or obtain a new mortgage?

	Important	Not Important
Change to a fixed-rate loan	☐	☐
Get a lower interest rate	☐	☐
Remove private mortgage insurance	☐	☐
Get a lower monthly payment	☐	☐
Consolidate or pay down other debt	☐	☐
Repay the loan more quickly	☐	☐
Take out cash	☐	☐

37. Approximately how much was owed, in total, on the old mortgage(s) and loan(s) you refinanced?

$ ______ .00

☐ Zero *(the property was mortgage-free)*

38. Did you use the money you got from this new mortgage for any of the following?

	Yes	No
College expenses	☐	☐
Auto or other major purchase	☐	☐
Buy out co-signer(s)/co-owner(s)	☐	☐
Pay off other bills or debts	☐	☐
Home repairs or new construction	☐	☐
Savings	☐	☐
Closing costs of new mortgage	☐	☐
Business or investment	☐	☐
Other (specify) ______	☐	☐

☐ Did not get money from refinancing

This Mortgage

39. When you took out this most recent mortgage or refinance, what was the dollar amount you borrowed?

$ ______ .00 ☐ Don't know

40. What is the monthly payment, including the amount paid to escrow for taxes and insurance?

$ ______ .00 ☐ Don't know

41. What is the interest rate on this mortgage?

______ % ☐ Don't know

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42. Which one of the following best describes how you decided on the interest rate of your mortgage?

- ☐ Paid higher closing costs to get lower interest rate
- ☐ Paid lower closing costs with a higher interest rate
- ☐ Got a balance between closing costs and interest rate

43. Does this mortgage have…

	Yes	No	Don't Know
A prepayment penalty *(fee if the mortgage is paid off early)*	☐	☐	☐
An escrow account for taxes and/or homeowner insurance	☐	☐	☐
An adjustable rate *(one that can change over the life of the loan)*	☐	☐	☐
A balloon payment	☐	☐	☐
Interest-only payments	☐	☐	☐
Private mortgage insurance	☐	☐	☐
Lender-required flood insurance	☐	☐	☐

44. At any time after you made your final loan application did any of the following change?

	Higher	Same	Lower
Monthly payment	☐	☐	☐
Interest rate	☐	☐	☐
Other fees	☐	☐	☐
Amount of money needed to close loan	☐	☐	☐

45. The "Closing Disclosure" statement you received at closing shows the loan closing costs and other closing costs separately. What were the loan closing costs you paid on this loan?

$ __________ .00 ☐ Don't know

46. How were the total closing costs (loan costs and other costs) for this loan paid?

	Yes	No	Don't Know
By me or a co-signer with a check or wire transfer	☐	☐	☐
Added to the mortgage amount	☐	☐	☐
By mortgage lender/broker	☐	☐	☐
By seller/builder	☐	☐	☐
Other (specify) __________	☐	☐	☐

☐ Loan had no closing costs

47. Were the loan costs you paid similar to what you had expected to pay based on the Loan Estimates or Closing Disclosures you received?

☐ Yes ☐ No

48. After closing on this mortgage, how much cash reserves in checking, savings, and other similar assets did you have remaining?

- ☐ Less than one month's mortgage payment
- ☐ 1-2 months' worth of mortgage payments
- ☐ 3-6 months' worth of mortgage payments
- ☐ 7 months' worth or more of mortgage payments

49. Did you seek input about your closing documents from any of the following people?

	Yes	No
Mortgage lender/broker	☐	☐
Settlement/closing agent	☐	☐
Real estate agent	☐	☐
Personal attorney	☐	☐
Title insurance agent	☐	☐
Trusted friend or relative who is not a co-signer on the mortgage	☐	☐
Housing counselor	☐	☐
Other (specify) __________	☐	☐

50. Did you face any of the following at your <u>loan closing</u>?

	Yes	No
Loan documents not ready at closing	☐	☐
Closing did not occur as originally scheduled	☐	☐
Three-day rule required re-disclosure	☐	☐
Mortgage terms different at closing than expected, e.g. interest rate, monthly payment	☐	☐
More cash needed at closing than expected, e.g. escrow, unexpected fees	☐	☐
Less cash needed at closing than expected	☐	☐
Asked to sign blank documents at closing	☐	☐
Asked to sign pre-dated or post-dated documents at closing	☐	☐
Felt rushed at closing or not given time to read documents	☐	☐

51. Is there any <u>additional problem</u> you encountered while getting this mortgage that you'd like to tell us about?

____

____

____

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52. At the same time you took out this mortgage, did you also take out another loan on the property you financed with this mortgage *(a second lien, home equity loan, or a home equity line of credit (HELOC))*?

☐ Yes
☐ No → **Skip to 54**

53. What was the amount of this loan?

$ ______ .00

☐ Don't know

54. How well could you explain to someone the…

	Very	Somewhat	Not At All
Process of taking out a mortgage	☐	☐	☐
Difference between a fixed- and an adjustable-rate mortgage	☐	☐	☐
Difference between a prime and subprime loan	☐	☐	☐
Difference between a mortgage's interest rate and its APR	☐	☐	☐
Amortization of a loan	☐	☐	☐
Consequences of not making required mortgage payments	☐	☐	☐
Difference between lender's and owner's title insurance	☐	☐	☐
Relationship between discount points and interest rate	☐	☐	☐
Reason payments into an escrow account can change	☐	☐	☐

This Mortgaged Property

55. When did you first become the owner of this property?

______ / ______
month year

56. What was the purchase price of this property, or if you built it, how much did the construction and land cost?

$ ______ .00 ☐ Don't know

57. Which one of the following best describes how you acquired this property?

☐ Purchased an existing home
☐ Purchased a newly-built home from a builder
☐ Had or purchased land and built a house
☐ Received as a gift or inheritance
☐ Other (specify) ______

58. Which one of the following best describes this property?

☐ Single-family detached house
☐ Mobile home or manufactured home
☐ Townhouse, row house, or villa
☐ 2-unit, 3-unit, or 4-unit dwelling
☐ Apartment (or condo/co-op) in apartment building
☐ Unit in a partly commercial structure
☐ Other (specify) ______

59. Does this mortgage cover more than one unit?

☐ Yes ☐ No

60. About how much do you think this property is worth in terms of what you could sell it for now?

$ ______ .00 ☐ Don't know

61. Do you rent out all or any portion of this property?

☐ Yes
☐ No → **Skip to 63**

62. How much rent do you receive annually?

$ ______ .00 per year

63. Besides you, the mortgage co-signers, and renters, does anyone else help pay the expenses for this property?

☐ Yes ☐ No

64. Which one of the following best describes how you use this property?

☐ Primary residence *(where you spend the majority of your time)*
☐ It will be my primary residence soon
☐ Seasonal or second home
☐ Home for other relatives
☐ Rental or investment property
☐ Other (specify) ______

Skip to 67 on page 7

65. If primary residence, when did you move into this property?

______ / ______
month year

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66. **Which one of the following best describes your willingness or ability to move from your primary residence?**

- ☐ Willing and able to move
- ☐ Willing but unable to move
- ☐ Unwilling to move
- ☐ Unsure/Don't know at this time

67. **In the last couple years, how have the following changed in the neighborhood where this property is located?**

	Significant Increase	Little/No Change	Significant Decrease
Number of homes for sale	☐	☐	☐
Number of vacant homes	☐	☐	☐
Number of homes for rent	☐	☐	☐
Number of foreclosures or short sales	☐	☐	☐
Number of homes impacted by natural disasters	☐	☐	☐
House prices	☐	☐	☐
Overall desirability of living there	☐	☐	☐

68. **What do you think will happen to the prices of homes in this neighborhood over the next couple of years?**

- ☐ Increase a lot
- ☐ Increase a little
- ☐ Remain about the same
- ☐ Decrease a little
- ☐ Decrease a lot

69. **In the next couple of years, how do you expect the overall desirability of living in this neighborhood to change?**

- ☐ Become more desirable
- ☐ Stay about the same
- ☐ Become less desirable

70. **How likely is it that in the next couple of years you will…**

	Very	Somewhat	Not At All
Sell this property	☐	☐	☐
Move but keep this property	☐	☐	☐
Refinance the mortgage on this property	☐	☐	☐
Pay off this mortgage and own the property mortgage-free	☐	☐	☐

Your Household

71. **What is your current marital status?**

- ☐ Married
- ☐ Separated
- ☐ Never married
- ☐ Divorced
- ☐ Widowed

72. **Do you have a partner who shares the decision-making and responsibilities of running your household but is not your legal spouse?**

☐ Yes ☐ No

Please answer the following questions for you and your spouse or partner, if applicable.

73. **Age at last birthday:**

	You	Spouse/ Partner
	____ years	____ years

74. **Sex:**

	You	Spouse/ Partner
Male	☐	☐
Female	☐	☐

75. **Highest level of education achieved:**

	You	Spouse/ Partner
Some schooling	☐	☐
High school graduate	☐	☐
Technical school	☐	☐
Some college	☐	☐
College graduate	☐	☐
Postgraduate studies	☐	☐

76. **Hispanic or Latino:**

	You	Spouse/ Partner
Yes	☐	☐
No	☐	☐

77. **Race:** *Mark all that apply.*

	You	Spouse/ Partner
White	☐	☐
Black or African American	☐	☐
American Indian or Alaska Native	☐	☐
Asian	☐	☐
Native Hawaiian or Other Pacific Islander	☐	☐

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78. Current work status: *Mark all that apply.*

	You	Spouse/ Partner
Self-employed full time	☐	☐
Self-employed part time	☐	☐
Employed full time	☐	☐
Employed part time	☐	☐
Retired	☐	☐
Unemployed, temporarily laid-off or on leave	☐	☐
Not working for pay *(student, homemaker, disabled)*	☐	☐

79. Ever served on active duty in the U.S. Armed Forces, Reserves or National Guard?

	You	Spouse/ Partner
Never served in the military	☐	☐
Only on active duty for training in the Reserves or National Guard	☐	☐
Now on active duty	☐	☐
On active duty in the past, but not now	☐	☐

80. Besides you (and your spouse/partner) who else lives in your household? *Mark all that apply.*

☐ Children/grandchildren under age 18
☐ Children/grandchildren age 18 – 22
☐ Children/grandchildren age 23 or older
☐ Parents of you or your spouse or partner
☐ Other relatives like siblings or cousins
☐ Non-relative

☐ No one else

81. Do you speak a language other than English at home?

☐ Yes
☐ No → **Skip to 84**

82. Was it important to get your mortgage documents in this language?

☐ Yes ☐ No

83. Did you get mortgage documents in this language?

☐ Yes ☐ No

84. Approximately how much is your total annual household income from all sources *(wages, salaries, tips, interest, child support, investment income, retirement, social security, and alimony)*?

☐ Less than $35,000
☐ $35,000 to $49,999
☐ $50,000 to $74,999
☐ $75,000 to $99,999
☐ $100,000 to $174,999
☐ $175,000 or more

85. How does this total annual household income compare to what it is in a "normal" year?

☐ Higher than normal
☐ Normal
☐ Lower than normal

86. Does your total annual household income include any of the following sources?

	Yes	No
Wages or salary	☐	☐
Business or self-employment	☐	☐
Interest or dividends	☐	☐
Alimony or child support	☐	☐
Social Security, pension or other retirement benefits	☐	☐

87. Does anyone in your household have any of the following?

	Yes	No
401(k), 403(b), IRA, or pension plan	☐	☐
Stocks, bonds, or mutual funds (*not in retirement accounts or pension plans*)	☐	☐
Certificates of deposit	☐	☐
Investment real estate	☐	☐

88. Which one of the following statements best describes the amount of financial risk you are willing to take when you save or make investments?

☐ Take substantial financial risks expecting to earn substantial returns
☐ Take above-average financial risks expecting to earn above-average returns
☐ Take average financial risks expecting to earn average returns
☐ Not willing to take any financial risks

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89. Do you agree or disagree with the following statements?

	Agree	Disagree
Owning a home is a good financial investment	☐	☐
Most mortgage lenders generally treat borrowers well	☐	☐
Most mortgage lenders would offer me roughly the same rates and fees	☐	☐
Late payments will lower my credit rating	☐	☐
Lenders shouldn't care about any late payments, only whether loans are fully repaid	☐	☐
It is okay to default or stop making mortgage payments if it is in the borrower's financial interest	☐	☐
I would consider counseling or taking a course about managing my finances if I faced financial difficulties	☐	☐

90. In the last couple of years, have any of the following happened to you?

	Yes	No
Separated, divorced or partner left	☐	☐
Married, remarried or new partner	☐	☐
Death of a household member	☐	☐
Addition to your household (not spouse/partner)	☐	☐
Person leaving your household (not spouse/partner)	☐	☐
Disability or serious illness of household member	☐	☐
Disaster affecting a property you own	☐	☐
Disaster affecting your (or your spouse/partner's) work	☐	☐
Moved within the area (less than 50 miles)	☐	☐
Moved to a new area (50 miles or more)	☐	☐

91. In the last couple of years, have any of the following happened to you (or your spouse/partner)?

	Yes	No
Layoff, unemployment, or reduced hours of work	☐	☐
Retirement	☐	☐
Promotion	☐	☐
Starting a new job	☐	☐
Starting a second job	☐	☐
Business failure	☐	☐
A personal financial crisis	☐	☐

92. In the last couple years, how have the following changed for you (and your spouse/partner)?

	Significant Increase	Little/No Change	Significant Decrease
Household income	☐	☐	☐
Housing expenses	☐	☐	☐
Non-housing expenses	☐	☐	☐

93. In the next couple of years, how do you expect the following to change for you (and your spouse/partner)?

	Significant Increase	Little/No Change	Significant Decrease
Household income	☐	☐	☐
Housing expenses	☐	☐	☐
Non-housing expenses	☐	☐	☐

94. How likely is it that in the next couple of years you (or your spouse/partner) will face…

	Very	Somewhat	Not At All
Retirement	☐	☐	☐
Difficulties making your mortgage payments	☐	☐	☐
A layoff, unemployment, or forced reduction in hours	☐	☐	☐
Some other personal financial crisis	☐	☐	☐

95. If your household faced an unexpected personal financial crisis in the next couple of years, how likely is it you could…

	Very	Somewhat	Not At All
Pay your bills for the next 3 months without borrowing	☐	☐	☐
Get significant financial help from family or friends	☐	☐	☐
Borrow a significant amount from a bank or credit union	☐	☐	☐
Significantly increase your income	☐	☐	☐

96. In the next ten years, what do you think could decrease the value of a property you own?

____

____

____

____

____

____

____

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Thank you for completing this survey and sharing your experiences to help improve the processes of getting a mortgage.

We have provided space below for any additional comments.
Is there anything else you would like to tell us about your experience getting a mortgage to purchase or refinance your property?
Please do not put your name or address on the questionnaire.

Please use the enclosed business reply envelope to return your completed questionnaire.
FHFA
1600 Research Blvd, RC B16
Rockville, MD 20850

For any questions about the survey or online access you can call toll free 1-855-339-7877.

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[FR Doc. 2022–26420 Filed 12–5–22; 8:45 am]

BILLING CODE 8070–01–C

FEDERAL RESERVE SYSTEM

Formations of, Acquisitions by, and Mergers of Savings and Loan Holding Companies

The companies listed in this notice have applied to the Board for approval, pursuant to the Home Owners' Loan Act (12 U.S.C. 1461 *et seq.*) (HOLA), Regulation LL (12 CFR part 238), and Regulation MM (12 CFR part 239), and all other applicable statutes and regulations to become a savings and loan holding company and/or to acquire the assets or the ownership of, control of, or the power to vote shares of a savings association.

The public portions of the applications listed below, as well as other related filings required by the Board, if any, are available for immediate inspection at the Federal Reserve Bank(s) indicated below and at the offices of the Board of Governors. This information may also be obtained on an expedited basis, upon request, by contacting the appropriate Federal Reserve Bank and from the Board's Freedom of Information Office at *https://www.federalreserve.gov/foia/request.htm.* Interested persons may express their views in writing on whether the proposed transaction complies with the standards enumerated in the HOLA (12 U.S.C. 1467a(e)). If the proposal also involves the acquisition of a nonbanking company, the review also includes whether the acquisition of the nonbanking company complies with the standards in section 10(c)(4)(B) of the HOLA (12 U.S.C. 1467a(c)(4)(B)). Unless otherwise noted, nonbanking activities will be conducted throughout the United States.

Comments regarding each of these applications must be received at the Reserve Bank indicated or the offices of the Board of Governors, Ann E. Misback, Secretary of the Board, 20th Street and Constitution Avenue NW, Washington, DC 20551–0001, not later than January 4, 2023.

A. Federal Reserve Bank of Chicago (Colette A. Fried, Assistant Vice President) 230 South LaSalle Street, Chicago, Illinois 60690–1414:

1. *Fidelity Federal Bancorp, Evansville, Indiana, and its parent companies, Pedcor Financial, LLC and Pedcor Financial Bancorp, both of Carmel, Indiana;* to become savings and loan holding companies, following their conversion to bank holding companies through the acquisition of Rockhold Bancorp and its subsidiary, Bank of Kirksville, both of Kirksville, Missouri, as published elsewhere in today's **Federal Register**.

Board of Governors of the Federal Reserve System.

Margaret McCloskey Shanks,

Deputy Secretary of the Board.

[FR Doc. 2022–26419 Filed 12–5–22; 8:45 am]

BILLING CODE P

FEDERAL RESERVE SYSTEM

Formations of, Acquisitions by, and Mergers of Bank Holding Companies

The companies listed in this notice have applied to the Board for approval, pursuant to the Bank Holding Company Act of 1956 (12 U.S.C. 1841 *et seq.*) (BHC Act), Regulation Y (12 CFR part 225), and all other applicable statutes and regulations to become a bank holding company and/or to acquire the assets or the ownership of, control of, or the power to vote shares of a bank or bank holding company and all of the banks and nonbanking companies owned by the bank holding company, including the companies listed below.

The public portions of the applications listed below, as well as other related filings required by the Board, if any, are available for immediate inspection at the Federal Reserve Bank(s) indicated below and at the offices of the Board of Governors. This information may also be obtained on an expedited basis, upon request, by contacting the appropriate Federal Reserve Bank and from the Board's Freedom of Information Office at *https://www.federalreserve.gov/foia/request.htm.* Interested persons may express their views in writing on the standards enumerated in the BHC Act (12 U.S.C. 1842(c)).

Comments regarding each of these applications must be received at the Reserve Bank indicated or the offices of the Board of Governors, Ann E. Misback, Secretary of the Board, 20th Street and Constitution Avenue NW, Washington, DC 20551–0001, not later than January 4, 2023.

A. Federal Reserve Bank of Kansas City (Jeffrey Imgarten, Assistant Vice President) 1 Memorial Drive, Kansas City, Missouri 64198–0001:

1. *Mesa West Bancorp, Farmington, New Mexico;* to become a bank holding company by acquiring Four Corners Community Bank, Farmington, New Mexico.

B. Federal Reserve Bank of Chicago (Colette A. Fried, Assistant Vice President) 230 South LaSalle Street, Chicago, Illinois 60690–1414:

1. *Fidelity Federal Bancorp, Evansville, Indiana, and its parent companies Pedcor Financial, LLC and Pedcor Financial Bancorp, both of Carmel, Indiana;* to become bank holding companies by acquiring Rockhold Bancorp, and thereby indirectly acquiring Bank of Kirksville, both of Kirksville, Missouri, and also to retain its subsidiary, United Fidelity Bank, F.S.B., Evansville, Indiana, for a moment in time and thereby engage in operating a savings association.

2. *Fisher Bancorp Inc. Fisher, Illinois;* to merge with Butler Point Inc. and thereby indirectly acquire Catlin Bank, both of Catlin, Illinois.

Board of Governors of the Federal Reserve System.

Margaret McCloskey Shanks,

Deputy Secretary of the Board.

[FR Doc. 2022–26421 Filed 12–5–22; 8:45 am]

BILLING CODE P

FEDERAL TRADE COMMISSION

[File No. 202–3092]

iHeartMedia, Inc. and Google LLC; Analysis of Proposed Consent Order to Aid Public Comment

AGENCY: Federal Trade Commission.

ACTION: Proposed consent agreement; request for comment.

SUMMARY: The consent agreement in this matter settles alleged violations of federal law prohibiting unfair or deceptive acts or practices. The attached Analysis of Proposed Consent Order to Aid Public Comment describes both the allegations in the draft complaint and the terms of the consent order—embodied in the consent agreement—that would settle these allegations.

DATES: Comments must be received on or before January 5, 2023.

ADDRESSES: Interested parties may file comments online or on paper by following the instructions in the Request for Comment part of the **SUPPLEMENTARY INFORMATION** section below. Please write ''IHeartMedia, Inc. and Google LLC; File No. 202–3092'' on your comment and file your comment online at *https://www.regulations.gov* by following the instructions on the web-based form. If you prefer to file your comment on paper, mail your comment to the following address: Federal Trade Commission, Office of the Secretary, 600 Pennsylvania Avenue NW, Suite CC–5610 (Annex D), Washington, DC 20580.

FOR FURTHER INFORMATION CONTACT: Karen Mandel (202–326–2491) or Laura Sullivan (202–326–3327), Bureau of Consumer Protection, Federal Trade Commission, 600 Pennsylvania Avenue NW, Washington, DC 20580.

SUPPLEMENTARY INFORMATION: Pursuant to Section 6(f) of the Federal Trade Commission Act, 15 U.S.C. 46(f), and FTC Rule § 2.34, 16 CFR 2.34, notice is hereby given that the above-captioned consent agreement containing a consent order to cease and desist, having been filed with and accepted, subject to final approval, by the Commission, has been placed on the public record for a period of 30 days. The following Analysis to Aid Public Comment describes the terms of the consent agreement and the allegations in the complaint. An electronic copy of the full text of the consent agreement package can be obtained at *https://www.ftc.gov/news-events/commission-actions.*

You can file a comment online or on paper. For the Commission to consider your comment, we must receive it on or before January 5, 2023. Write ''iHeartMedia, Inc. and Google LLC; File No. 202–3092'' on your comment. Your comment—including your name and your state—will be placed on the public record of this proceeding, including, to the extent practicable, on the *https://www.regulations.gov* website.

Because of the agency's heightened security screening, postal mail addressed to the Commission will be subject to delay. We strongly encourage you to submit your comments online through the *https://www.regulations.gov* website.

If you prefer to file your comment on paper, write ''iHeartMedia, Inc. and Google LLC; File No. 202–3092'' on your comment and on the envelope and mail your comment to the following address: Federal Trade Commission, Office of the Secretary, 600 Pennsylvania Avenue NW, Suite CC–5610 (Annex D), Washington, DC 20580.

Because your comment will be placed on the publicly accessible website at *https://www.regulations.gov,* you are solely responsible for making sure your comment does not include any sensitive or confidential information. In particular, your comment should not include sensitive personal information, such as your or anyone else's Social Security number; date of birth; driver's license number or other state identification number, or foreign country equivalent; passport number; financial account number; or credit or debit card number. You are also solely responsible for making sure your comment does not include sensitive health information, such as medical records or other individually identifiable health information. In addition, your comment should not include any ''trade secret or any commercial or financial information which . . . is privileged or confidential''—as provided by Section 6(f) of the FTC Act, 15 U.S.C. 46(f), and FTC Rule § 4.10(a)(2), 16 CFR 4.10(a)(2)—including competitively sensitive information such as costs, sales statistics, inventories, formulas, patterns, devices, manufacturing processes, or customer names.

Comments containing material for which confidential treatment is requested must be filed in paper form, must be clearly labeled ''Confidential,'' and must comply with FTC Rule § 4.9(c). In particular, the written request for confidential treatment that accompanies the comment must include the factual and legal basis for the request and must identify the specific portions of the comment to be withheld from the public record. *See* FTC Rule § 4.9(c). Your comment will be kept confidential only if the General Counsel grants your request in accordance with the law and the public interest. Once your comment has been posted on the *https://www.regulations.gov* website—as legally required by FTC Rule § 4.9(b)—we cannot redact or remove your comment from that website, unless you submit a confidentiality request that meets the requirements for such treatment under FTC Rule § 4.9(c), and the General Counsel grants that request.

Visit the FTC website at *https://www.ftc.gov* to read this document and the news release describing the proposed settlement. The FTC Act and other laws that the Commission administers permit the collection of public comments to consider and use in this proceeding, as appropriate. The Commission will consider all timely and responsive public comments that it receives on or before January 5, 2023. For information on the Commission's privacy policy, including routine uses permitted by the Privacy Act, see *https://www.ftc.gov/site-information/privacy-policy.*

Analysis of Proposed Consent Order To Aid Public Comment

The Federal Trade Commission (''Commission'') has accepted, subject to final approval, an agreement containing a consent order as to iHeartMedia, Inc. (''iHeartMedia'' or ''respondent''). The proposed consent order (''order'') has been placed on the public record for 30 days for receipt of comments by interested persons. Comments received during this period will become part of the public record. After 30 days, the Commission will again review the order and the comments received and will decide whether it should withdraw the order or make it final.

This matter involves iHeartMedia's practices with respect to advertising it recorded and broadcast for the Google LLC Pixel 4 smartphone (the ''Pixel 4''). The complaint alleges that iHeartMedia recorded first-person endorsements for the Pixel 4 by its local radio personalities in several states using scripts provided by Google LLC and broadcast those advertisements to consumers in those markets. The complaint further alleges that, in the advertising, the respondent represented that the radio personalities owned or regularly used the Pixel 4, and had used it to take pictures at night, when the radio personalities did not own or regularly use the phone and had not used it to take pictures at night. The complaint alleges that iHeartMedia's representations were false and misleading, and violated Section 5(a) of the FTC Act.

The order includes injunctive relief that prohibits the alleged violations and fences in similar and related conduct. The provisions apply to any consumer product or service.

Part I prohibits misrepresenting that an endorser has owned or used any consumer product or service or about an endorser's experience with any consumer product or service. Part II requires the respondent to cooperate in any Commission investigation or case related to the conduct that is the subject of the complaint. Part III requires the respondent to distribute the order to certain persons and submit signed acknowledgments of order receipt.

Part IV requires the respondent to file compliance reports with the Commission, and to notify the Commission of changes in corporate structure that might affect compliance obligations. Part V contains recordkeeping requirements for certain accounting records, personnel records, consumer complaints, training materials, and advertising and marketing materials, and all records necessary to demonstrate compliance with the order.

Part VI contains other requirements related to the Commission's monitoring of the respondent's order compliance. Part VII provides the effective dates of the order, including that, with exceptions, the order will terminate in 20 years.

The purpose of this analysis is to facilitate public comment on the order, and it is not intended to constitute an official interpretation of the complaint or order, or to modify the order's terms in any way.

By direction of the Commission.

April J. Tabor,

Secretary.

[FR Doc. 2022–26492 Filed 12–5–22; 8:45 am]

BILLING CODE 6750–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[CMS–3431–N2]

Medicare Program; Virtual Meeting of the Medicare Evidence Development and Coverage Advisory Committee; Cancellation of the December 7, 2022 Virtual Meeting and Announcement of the February 13 and February 14, 2023 Virtual Meetings

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

ACTION: Notice.

SUMMARY: This notice announces the cancellation of the December 7, 2022 virtual public meeting of the Medicare Evidence Development & Coverage Advisory Committee (MEDCAC) (''Committee'') that was published in the October 11, 2022 **Federal Register**. This notice also announces a virtual public meeting of the MEDCAC Committee on Monday, February 13 and

Tuesday, February 14, 2023. National Coverage Determinations resulting in coverage with evidence development (CED) can expedite earlier Medicare beneficiary access to innovative technology while ensuring that systematic patient safeguards are in place to reduce the risks inherent to new technologies, or to new applications of older technologies. This meeting will examine the general requirements for clinical studies submitted for CMS coverage requiring CED. The MEDCAC will evaluate the CED criteria to assure that CED studies are evaluated with consistent, feasible, transparent and methodologically rigorous criteria and advise CMS on whether the criteria are appropriate to ensure that CED-approved studies will produce reliable evidence that CMS can rely on to help determine whether a particular item or service is reasonable and necessary. This meeting is open to the public in accordance with the Federal Advisory Committee Act.

DATES:

Meeting Date: The virtual meeting will be held on Monday, February 13 and Tuesday, February 14, 2023 from 10:00 a.m. until 3:00 p.m., Eastern Standard Time (EST).

Deadline for Submission of Written Comments: Written comments must be received at the email address specified in the **ADDRESSES** section of this notice by 5:00 p.m., Eastern Standard Time (EST), on Friday, January 13, 2023. Once submitted, all comments are final.

Deadlines for Speaker Registration and Presentation Materials: The deadline to register to be a speaker and to submit PowerPoint presentation materials and writings that will be used in support of an oral presentation is 5:00 p.m., EST, on Friday, January 13, 2023. Speakers may register by phone or via email by contacting the person listed in the **FOR FURTHER INFORMATION CONTACT** section of this notice. Presentation materials must be received at the email address specified in the **ADDRESSES** section of this notice.

Submission of Presentations and Comments: Presentation materials and written comments that will be presented at the meeting must be submitted via email to *MedCACpresentations@cms.hhs.gov* section of this notice by Friday, January 13, 2023.

Deadline for All Other Attendees Registration: Individuals who want to join the meeting may register online at *https://cms.zoomgov.com/webinar/register/WN_CsJL7k7kQcyY0Z20OR6eqw* by 11:59 p.m. EST, on Sunday, February 12, 2023.

Webinar and Teleconference Meeting Information: Teleconference dial-in instructions, and related webinar details will be posted on the meeting agenda, which will be available on the CMS website *http://www.cms.gov/medicare-coverage-database/indexes/medcac-meetings-index.aspx?bc=BAAAAAAAAAAA&.* Participants in the MEDCAC meeting will require the following: A computer, laptop or smartphone where the Zoom application needs to be downloaded; a strong Wi-Fi or an internet connection and access to use Chrome or Firefox web browser and a webcam if the meeting participant is scheduled to speak or make a presentation during the meeting.

Deadline for Submitting a Request for Special Accommodations: Individuals viewing or listening to the meeting who are hearing or visually impaired and have special requirements, or a condition that requires special assistance, should send an email to the MEDCAC Coordinator as specified in the **FOR FURTHER INFORMATION CONTACT** section of this notice no later than 5:00 p.m., EST on Monday, January 23, 2023.

ADDRESSES: Due to the current COVID–19 public health emergency, the Panel meeting will be held *virtually* and *will not* occur at the campus of the Centers for Medicare & Medicaid Services (CMS), Central Building, 7500 Security Boulevard, Baltimore, Maryland 21244.

FOR FURTHER INFORMATION CONTACT: Tara Hall, MEDCAC Coordinator, via email at *Tara.Hall@cms.hhs.gov* or by phone 410–786–4347.

SUPPLEMENTARY INFORMATION:

I. Background

MEDCAC, formerly known as the Medicare Coverage Advisory Committee (MCAC), is advisory in nature, with all final coverage decisions resting with CMS. MEDCAC is used to supplement CMS' internal expertise. Accordingly, the advice rendered by the MEDCAC is most useful when it results from a process of full scientific inquiry and thoughtful discussion, in an open forum, with careful framing of recommendations and clear identification of the basis of those recommendations. MEDCAC members are valued for their background, education, and expertise in a wide variety of scientific, clinical, and other related fields. (For more information on MEDCAC, see the MEDCAC Charter (*http://www.cms.gov/Regulations-and-Guidance/Guidance/FACA/Downloads/medcaccharter.pdf*) and the CMS Guidance Document, *Factors CMS Considers in Referring Topics to the MEDCAC* (*http://www.cms.gov/medicare-coverage-database/details/medicare-coverage-document-details.aspx?MCDId=10*).

II. Meeting Topic and Format

This notice announces the February 13 and February 14, 2023, virtual public meeting of the Committee. This meeting will examine the requirements for clinical studies submitted for CMS coverage under coverage with evidence development (CED). It has been 8 years since the criteria for CED were last evaluated and revised. In that time, not only have technologies become more complex, but there has been growing appreciation and commitment to transparency in decision-making, to making certain that study methodologies are ''fit to purpose'' as determined by the topic, questions asked, health outcomes studied, and to making certain that the populations studied are representative of the diversity in the Medicare beneficiary population. For example, some questions may be sufficiently answered through analysis of real-world evidence including data from clinical registries, electronic health records, and administrative claims. Any decision about whether an item or service is reasonable and necessary must, minimally, be sensitive to these commitments as well as to ensuring that study participants' interests are respected and protected. The MEDCAC will evaluate the CED criteria to assure that CED studies are evaluated with consistent, feasible, transparent and methodologically rigorous criteria and advise on whether the criteria are appropriate to ensure that CED-approved studies will produce reliable evidence that CMS can rely on to help determine whether a particular item or service is reasonable and necessary.

Background information about this topic, including panel materials, is available at *http://www.cms.gov/medicare-coverage-database/indexes/medcac-meetings-index.aspx?bc=BAAAAAAAAAAA&.* Electronic copies of all the meeting materials will be on the CMS website no later than 2 business days before the meeting. We encourage the participation of organizations, researchers and people with expertise or interest in the thoughtful, efficient design and implementation of clinical studies whose goals are to improve the health of people, especially Medicare beneficiaries. This meeting is open to the public. The Committee will hear oral presentations from the public. Time allotted for each presentation may be limited. If the number of registrants requesting to speak is greater than what can be reasonably accommodated during the scheduled open public hearing session, we 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 no later than 1 week from the speaker registration deadline specified in the **DATES** section of this notice. Your comments must focus on issues specific to the list of topics that we have proposed to the Committee. The list of research topics to be discussed at the meeting will be available on the following website prior to the meeting *http://www.cms.gov/medicare-coverage-database/indexes/medcac-meetings-index.aspx?bc=BAAAAAAAAAAA&*. We require that you declare at the meeting whether you have any financial involvement with manufacturers (or their competitors) of any items or services being discussed. Speakers presenting at the MEDCAC meeting must include a full disclosure slide as their second slide in their presentation for financial interests (for example, type of financial association—consultant, research support, advisory board, and an indication of level, such as minor association <$10,000 or major association> $10,000) as well as intellectual conflicts of interest (for example, involvement in a federal or nonfederal advisory committee that has discussed the issue) that may pertain in any way to the subject of this meeting. If you are representing an organization, we require that you also disclose conflict of interest information for that organization. If you do not have a PowerPoint presentation, you will need to present the full disclosure information requested previously at the beginning of your statement to the Committee.

The Committee will deliberate openly on the topics under consideration. Interested persons may observe the deliberations, but the Committee will not hear further comments during this time except at the request of the chairperson. The Committee will also allow a 15-minute unscheduled open public session for any attendee to address issues specific to the topics under consideration. By the conclusion of the second day, the panel members will vote and the Committee will make its recommendation(s) to CMS.

III. Registration Instructions

CMS' Coverage and Analysis Group is coordinating meeting registration. While there is no registration fee, individuals must register to attend. You may register online at *https://cms.zoomgov.com/webinar/register/WN_CsJL7k7kQcyY0Z20OR6eqw* or by phone by contacting the person listed in the **FOR FURTHER INFORMATION CONTACT** section of this notice by the deadline listed in the **DATES** section of this notice. Please provide your full name (as it appears on your state-issued driver's license), address, organization, telephone number(s), and email address. You will receive a registration confirmation with instructions for your participation at the virtual public meeting.

IV. Collection of Information

This document does not impose information collection requirements, that is, reporting, recordkeeping or third-party disclosure requirements. Consequently, there is no need for review by the Office of Management and Budget under the authority of the Paperwork Reduction Act of 1995 (44 U.S.C. chapter 35).

The Chief Medical Officer and Director of the Center for Clinical Standards and Quality for the Centers for Medicare & Medicaid Services (CMS), Lee A. Fleisher, having reviewed and approved this document, authorizes Lynette Wilson, who is the Federal Register Liaison, to electronically sign this document for purposes of publication in the **Federal Register**.

Dated: December 1, 2022.

Lynette Wilson,

Federal Register Liaison, Centers for Medicare & Medicaid Services.

[FR Doc. 2022–26501 Filed 12–5–22; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Administration for Children and Families

[CFDA Number: 93.568]

Reallotment of Fiscal Year 2021 Funds for the Low Income Home Energy Program—Final

AGENCY: Office of Community Services (OCS), Administration for Children and Families (ACF), Department of Health and Human Services (HHS).

ACTION: Notice of final issuance.

SUMMARY: The ACF, OCS, Division of Energy Assistance (DEA) announces that $323,063 of funds from the fiscal year (FFY) 2021 Low Income Home Energy Assistance Program (LIHEAP) were reallotted to States, Territories, Tribes, and Tribal Organizations that received FFY 2022 direct LIHEAP grants.

DATES: This notice became effective on September 28, 2022, which is the day on which ACF awarded these reallotments.

FOR FURTHER INFORMATION CONTACT: Akm Rahman, Program Operations Branch Chief, Division of Energy Assistance, Office of Community Services, 330 C Street SW, 5th Floor; Mail Room 5425; Washington, DC 20201. Telephone: (202) 401–5306; Email: *Akm.Rahman@acf.hhs.gov.*

SUPPLEMENTARY INFORMATION: In accordance with Section 2607(b)(1) of the Low Income Home Energy Assistance Act (the Act), Title XXVI of the Omnibus Budget Reconciliation Act of 1981 (42 U.S.C. 8626(b)(1)), as amended, ACF published a notice in the **Federal Register** on September 30, 2022, 87 FR 59438, announcing the Secretary's preliminary determination that $711,932 of FFY 2021 funds for LIHEAP may be available for reallotment. No comments were received on this notice, nor did any recipients report additional funds for reallotment. However, after such publication, ACF discovered that one grant recipient could not adequately complete its necessary reporting, another grant recipient reported less unobligated funds in a revision, and three grant recipients had insufficient balances in their accounts in the Payment Management System.

These funds became available from the following grant recipients in the following amounts:

Name of grant recipient that returned funds for reallotment	FY 2021 reallotment amount
Bishop Paiute Tribe	$17,531
Colorado River Indian Tribes	16,914

Name of grant recipient that returned funds for reallotment	FY 2021 reallotment amount
Cow Creek Band of Umpqua Tribe of Indians	7,302
Hopland Band of Pomo Indians	1,755
Jicarilla Apache Nation	16,873
Kalispel Tribe of Indians	7,921
Makah Tribe	31,196
Muckleshoot Indian Tribe	37,669
Nooksack Indian Tribe	38,535
Paiute Indian Tribe of Utah	61,183
Quileute Tribe	1,673
Round Valley Indian Tribes	558
Sac and Fox Nation of Oklahoma	44,538
Samish Indian Nation	331
Shawnee Tribe	3,600
Spokane Tribe of Indians	19,905
The Delaware Tribe of Indians	15,579
Total	323,063

The list of grant recipients that were awarded these funds was published in a Dear Colleague Letter that is posted to ACF's website at *https://www.acf.hhs.gov/ocs/resource/dear-colleagues.*

Pursuant to the statute cited above, these funds were reallotted on September 28, 2022, to all but three types of FFY 2022 LIHEAP grant recipients by distributing them under the formula that Congress set for FFY 2022 funding. The three types of recipients that did not receive funds were (1) those whose allocations would have been less than $25; (2) tribes or tribal organizations that agreed with their co-territorial states to receive set amounts for the entire fiscal year; and (3) states or territories that were held to the additional minimum floor required by the FY 2022 appropriations act after including the reallotment amount. No sub-recipients of these recipients or other entities may apply for these funds.

The reallotted funds may be used for any purpose authorized under LIHEAP. Grant recipients must add these funds to their total LIHEAP funds payable for FFY 2022 for purposes of calculating statutory caps on administrative costs, carryover, Assurance 16 activities, and weatherization assistance. Grant recipients must also (1) ensure that these funds are included in the amounts that ACF pre-populated on Line 1.1 of their FFY 2022 Carryover and Reallotment Reports; (2) reconcile these funds, to the extent that they received them, on a separate Federal Financial Form (SF–425); and (3) record, on their FFY 2022 Household Reports, households that receive benefits at least partly from these funds. State recipients must also ensure that these funds are included in the Grantee Survey sections of their FFY 2022 LIHEAP Performance Data Forms.

OCS recommends that, after receiving them, grant recipients obligate these funds before obligating any other federal LIHEAP funds.

Statutory Authority: 42 U.S.C. 8626(b).

Karen D. Shields,

Senior Grants Policy Specialist, Office of Grants Policy, Office of Administration.

[FR Doc. 2022–26447 Filed 12–5–22; 8:45 am]

BILLING CODE 4184–80–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2021–D–0691]

Pharmacokinetic-Based Criteria for Supporting Alternative Dosing Regimens of Programmed Cell Death Receptor-1 or Programmed Cell Death-Ligand 1 Blocking Antibodies for Treatment of Patients With Cancer; 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 final guidance for industry entitled ''Pharmacokinetic-Based Criteria for Supporting Alternative Dosing Regimens of Programmed Cell Death Receptor-1 (PD-1) or Programmed Cell Death-Ligand 1 (PD-L1) Blocking Antibodies for Treatment of Patients with Cancer.'' This guidance provides recommendations for sponsors of investigational new drug applications (INDs) and biologics license applications (BLAs) on the use of pharmacokinetic (PK)-based criteria to support the approval of alternative dosing regimens for programmed cell death receptor-1 (PD-1) or programmed cell death-ligand 1 (PD-L1) blocking antibodies. This guidance is based on accumulated scientific and regulatory experience for PD-1 and PD-L1 drugs, and as such, does not address development of alternative dosing regimens for other drugs or biologics, changes in route of administration, or novel formulations of previously approved PD-1/PD-L1 products. This guidance finalizes the draft guidance of the same title issued on August 26, 2021.

DATES: The announcement of the guidance is published in the **Federal Register** on December 6, 2022.

ADDRESSES: You may submit either electronic or written comments on Agency guidances 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–2021–D–0691 for ''Pharmacokinetic-Based Criteria for Supporting Alternative Dosing Regimens of Programmed Cell Death Receptor-1 (PD-1) or Programmed Cell Death-Ligand 1 (PD-L1) Blocking Antibodies for Treatment of Patients with Cancer.'' 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 this 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 guidance document.

FOR FURTHER INFORMATION CONTACT: Brian Booth, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Avenue, Building 51, Silver Spring, MD 20993, 301–796–1508.

SUPPLEMENTARY INFORMATION:

I. Background

FDA is announcing the availability of a guidance for industry entitled ''Pharmacokinetic-Based Criteria for Supporting Alternative Dosing Regimens of Programmed Cell Death Receptor-1 (PD-1) or Programmed Cell Death-Ligand 1 (PD-L1) Blocking Antibodies for Treatment of Patients with Cancer.'' This guidance provides recommendations for sponsors of INDs and BLAs on the use of PK-based criteria to support the approval of alternative dosing regimens for PD-1 or PD-L1 blocking antibodies. The guidance is based on accumulated scientific and regulatory experience for PD-1 and PD-L1 drugs, as such, does not address development of alternative dosing regimens for any other drugs or biologics, changes in route of administration, or novel formulations of previously approved PD-1/PD-L1 products.

Sponsors may seek approval of alternative intravenous (IV) dosing regimens that are different from those tested in the original clinical efficacy and safety trials that served as the basis of approval of the current dosing regimen, or in the pre-approval setting, dosing regimens that differ from those tested in earlier PK and efficacy studies conducted during development. These alternative IV dosing regimens are typically designed to change doses and dosing intervals. Longer dosing intervals can minimize patient burden and reduce risks associated with more frequent administration (*e.g.,* infusion reactions), as well as exposure to communicable diseases (*e.g.,* SARS–CoV–2) associated with visits to hospitals or infusion centers. The guidance describes the criteria for using the PK-based approach and the documents that should be included in the submissions seeking approval.

This guidance finalizes the draft guidance of the same title issued on August 26, 2021 (86 FR 47649). FDA considered comments received on the draft guidance as it finalized the guidance. Changes from the draft to the final guidance include: (1) PK-based approach to support approval of alternative dosing regimens for PD-1/PD-L1 blocking antibody products may apply to pre- and post-approval setting and (2) this approach may apply to PD-1/PD-L1 monotherapies and combination regimens where the dose and/or dose schedule of the PD-1/PD-L1 is the only proposed change. In addition, editorial changes were made to improve clarity.

This guidance is being issued consistent with FDA's good guidance practices regulation (21 CFR 10.115). The guidance represents the current thinking of FDA on ''Pharmacokinetic-Based Criteria for Supporting Alternative Dosing Regimens of Programmed Cell Death Receptor-1 (PD-1) or Programmed Cell Death-Ligand 1 (PD-L1) Blocking Antibodies for Treatment of Patients with Cancer.'' It does not establish any rights for any person and is not binding on FDA or the public. You can use another 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 have been approved under OMB control number 0910–0014; and the collections of information in 21 CFR part 601 have been approved under OMB control number 0910–0338.

III. Electronic Access

Persons with access to the internet may obtain the 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: November 30, 2022.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2022–26464 Filed 12–5–22; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2019–D–1828]

E19 A Selective Approach to Safety Data Collection in Specific Late-Stage Pre-Approval or Post-Approval Clinical Trials; International Council for Harmonisation; 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 final guidance for industry entitled ''E19 A Selective Approach to Safety Data Collection in Specific Late-Stage Pre-approval or Post-Approval Clinical Trials.'' The final guidance was prepared under the auspices of the International Council for Harmonisation of Technical Requirements for Pharmaceuticals for Human Use (ICH), formerly the International Conference on Harmonisation. The guidance revises the draft guidance for industry entitled ''E19 Optimisation of Safety Data Collection'' issued in June 2019. The final guidance provides recommendations regarding appropriate use of a selective approach to safety data collection in some late-stage pre- or post-marketing studies of drugs where the safety profile, with respect to commonly occurring adverse events, is well understood and documented. The final guidance is intended to advance important clinical research questions through the conduct of clinical investigations that collect relevant patient data, which will enable an adequate benefit-risk assessment of the drug for its intended use, while reducing the burden to patients from unnecessary tests that may yield limited additional information.

DATES: The announcement of the guidance is published in the **Federal Register** on December 6, 2022.

ADDRESSES: You may submit either electronic or written comments on Agency guidances 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–2019–D–1828 for ''E19 A Selective Approach to Safety Data Collection in Specific Late-Stage Pre-approval or Post-Approval Clinical Trials.'' 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 this 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 (CBER), 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. The guidance may also be obtained by mail by calling CBER at 1–800–835–4709 or 240–402–8010. See the **SUPPLEMENTARY INFORMATION** section for electronic access to the guidance document.

FOR FURTHER INFORMATION CONTACT:

Regarding the guidance: Mary Thanh Hai, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 51, Rm. 2134, Silver Spring, MD 20993–0002, 301–796–2310, *Mary.ThanhHai@fda.hhs.gov.*

Regarding the ICH: Jill Adleberg, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 51, Rm. 6364, Silver Spring, MD 20993–0002, 301–796–5259, *Jill.Adleberg@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

FDA is announcing the availability of a final guidance for industry entitled ''E19 A Selective Approach to Safety Data Collection in Specific Late-Stage Pre-approval or Post-Approval Clinical Trials.'' The final guidance was prepared under the auspices of ICH. ICH has the mission of achieving greater regulatory harmonization worldwide to ensure that safe, effective, high-quality medicines are developed, registered, and maintained in the most resource-efficient manner.

By harmonizing the regulatory requirements in regions around the world, ICH guidelines have substantially reduced duplicative clinical studies, prevented unnecessary animal studies, standardized the reporting of important safety information, standardized marketing application submissions, and made many other improvements in the quality of global drug development and manufacturing and the products available to patients.

The six Founding Members of the ICH are FDA; the Pharmaceutical Research and Manufacturers of America; the European Commission; the European Federation of Pharmaceutical Industries Associations; the Japanese Ministry of Health, Labour, and Welfare; and the Japanese Pharmaceutical Manufacturers Association. The Standing Members of the ICH Association include Health Canada and Swissmedic. Additionally, the Membership of ICH has expanded to include other regulatory authorities and industry associations from around the world (refer to *https://www.ich.org/*).

ICH works by involving technical experts from both regulators and industry parties in detailed technical harmonization work and the application of a science-based approach to harmonization through a consensus-driven process that results in the development of ICH guidelines. The regulators around the world are committed to consistently adopting these consensus-based guidelines, realizing the benefits for patients and for industry.

As a Founding Regulatory Member of ICH, FDA plays a major role in the development of each of the ICH guidelines, which FDA then adopts and issues as guidance for industry. FDA's guidance documents do not establish legally enforceable responsibilities. Instead, they describe the Agency's current thinking on a topic and should be viewed only as recommendations, unless specific regulatory or statutory requirements are cited.

In April 2019, the ICH Assembly endorsed the draft guideline entitled ''E19 Optimisation of Safety Data Collection'' and agreed that the guideline should be made available for public comment. The guideline is the product of the Efficacy Expert Working Group of the ICH. In the **Federal Register** of June 27, 2019 (84 FR 30730), FDA published a notice announcing the availability of the draft guidance. The notice gave interested persons an opportunity to submit comments by September 25, 2019.

After consideration of the comments received and revisions to the guideline, a final draft of the guideline was submitted to the ICH Assembly and endorsed by the regulatory agencies in September 2022.

The final guidance provides recommendations regarding appropriate use of a selective approach to safety data collection in some late-stage pre- or post-marketing studies of drugs where the safety profile, with respect to commonly occurring adverse events, is well understood and documented. The final guidance is intended to advance important clinical research questions through the conduct of clinical investigations that collect relevant patient data, which will enable an adequate benefit-risk assessment of the drug for its intended use, while reducing the burden to patients from unnecessary tests that may yield limited additional information.

This guidance is being issued consistent with FDA's good guidance practices regulation (21 CFR 10.115). This guidance represents the current thinking of FDA on ''E19 A Selective Approach to Safety Data Collection in Specific Late-Stage Pre-approval or Post-Approval Clinical Trials.'' 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 have been approved under OMB control number 0910–0014. The collections of information in 21 CFR part 314 have been approved under OMB control number 0910–0001. The collections of information in 21 CFR part 601 have been approved under OMB control number 0910–0338. FDA's guidance entitled ''E6(R2) Good Clinical Practice: Integrated Addendum to ICH E6(R1)'' (available at *https://www.fda.gov/media/93884/download*) have been approved under OMB control number 0910–0843.

III. Electronic Access

Persons with access to the internet may obtain the final guidance at *https://www.regulations.gov, https://www.fda.gov/drugs/guidance-compliance-regulatory-information/guidances-drugs, https://www.fda.gov/vaccines-blood-biologics/guidance-compliance-regulatory-information-biologics/biologics-guidances*, or *https://www.fda.gov/regulatory-information/search-fda-guidance-documents.*

Dated: November 30, 2022.

Lauren K. Roth,

Associate Commissioner for Policy.

[FR Doc. 2022–26433 Filed 12–5–22; 8:45 am]

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DEPARTMENT OF HEALTH AND HUMAN SERVICES

Indian Health Service

Tribal Management Grant Program

Announcement Type: New.

Funding Announcement Number: HHS–2023–IHS–TMD–0001.

Assistance Listing (Catalog of Federal Domestic Assistance or CFDA) Number: 93.228.

Key Dates

Application Deadline Date: March 6, 2023.

Earliest Anticipated Start Date: April 20, 2023.

I. Funding Opportunity Description

Statutory Authority

The Indian Health Service (IHS) is accepting applications for grants for the Tribal Management Grant (TMG) Program. This program is authorized under the Snyder Act, 25 U.S.C. 13; the Transfer Act, 42 U.S.C. 2001(a); and the Indian Self-Determination and Education Assistance Act (ISDEAA), Public Law 93–638, as amended, 25 U.S.C. 5322(b)(2) and 25 U.S.C. 5322(e). This program is described in the Assistance Listings located at *https://sam.gov/content/home* (formerly known as the CFDA) under 93.228.

Background

The TMG Program is a competitive grant program that is capacity building and developmental in nature and has been available for federally recognized Indian Tribes and Tribal Organizations (T/TOs) since shortly after enactment of the ISDEAA in 1975. The TMG Program was established to assist T/TOs to prepare for assuming all or part of existing IHS programs, functions, services, and activities (PFSAs) and further develop and improve Tribal health management capabilities. The TMG Program provides competitive grants to T/TOs to establish goals and performance measures for current health programs, assess current management capacity to determine if new components are appropriate, analyze programs to determine if a T/TO's management is practicable, and develop infrastructure systems to manage or organize PFSAs.

Purpose

The purpose of this program is to enhance and develop health management infrastructure and assist T/TOs in assuming all or part of existing IHS PFSAs through a Title I ISDEAA contract and assist established Title I ISDEAA contractors and Title V ISDEAA compactors to further develop and improve management capability. In addition, Tribal Management Grants are available to T/TOs under the authority of 25 U.S.C. 5322(e) for the following:

1. Obtaining technical assistance from providers designated by the T/TOs (including T/TOs that operate mature contracts) for the purposes of program planning and evaluation, including the development of any management systems necessary for contract management, and the development of cost allocation plans for indirect cost rates.

2. Planning, designing, monitoring, and evaluating Federal programs serving T/TOs, including Federal administrative functions.

II. Award Information

Funding Instrument—Grant

Estimated Funds Available

The total funding identified for fiscal year (FY) 2023 is approximately $2,465,000. Individual award amounts for the first budget year are anticipated to be between $50,000 and $150,000. The funding available for competing and subsequent continuation awards issued under this announcement is subject to the availability of appropriations and budgetary priorities of the Agency. The IHS is under no obligation to make awards that are selected for funding under this announcement.

Anticipated Number of Awards

Approximately 14–16 awards will be issued under this program announcement.

Period of Performance

The TMG Project period of performance varies based on the project type selected. Period of performance is from 1 to 3 years. Please see the next section for additional details.

Eligible TMG Project Types, Maximum Funding Levels, and Periods of Performance

The TMG Program consists of four project types:

1. Feasibility study.
2. Planning.
3. Evaluation study.
4. Health management structure.

Applicants may submit applications for one project type only. An application must state the project type selected. Any application that addresses more than one project type will be considered ineligible and will not be reviewed. The maximum funding levels noted must include both direct and indirect costs. Application budgets may not exceed the maximum funding level or period of performance identified for a project type. Any application with a budget or period of performance that exceeds the maximum funding level or period of performance will be considered ineligible and will not be reviewed. Please refer to Section IV.5, ''Funding Restrictions,'' for further information regarding ineligible project activities.

1. FEASIBILITY STUDY (Maximum funding/project period: $70,000/12 months) A feasibility study must include a study of a specific IHS program or segment of a program to determine if Tribal management of the program is possible. The study shall present the planned approach, training, and resources required to assume Tribal management of the program. The study must include the following four components:

- Health needs and health care service assessments that identify existing health care services and delivery systems, program divisibility issues, health status indicators, unmet needs, volume projections, and demand analysis.
- Management analysis of existing management structures, proposed management structures, implementation plans and requirements, and personnel staffing requirements and recruitment barriers.
- Financial analysis of historical trends data, financial projections, new resource requirements for program management costs, and analysis of potential revenues from Federal/non-Federal sources.
- Decision statement/report that incorporates findings (sustainability, etc.), conclusions, and recommendations. The study and recommendations report is to be presented to the Tribal governing body for determination regarding whether Tribal program assumption is desirable or warranted.

2. PLANNING (Maximum funding/project period: $50,000/12 months) Planning projects involve data collection to establish goals and performance measures for health programs operation or anticipated PFSAs under a Title I contract. Planning projects will specify the design of health programs and the management systems (including appropriate policies and procedures) to accomplish the health priorities of the T/TO. For example, planning projects could include the development of a Tribe-specific health plan or a strategic health plan, etc. Please note that updated Healthy People information and Healthy People 2020 objectives are available in electronic format at *https://www.healthypeople.gov/2020/topics-objectives.* The United States (U.S.) Public Health Service encourages applicants submitting strategic health plans to address specific objectives of Healthy People 2020.

3. EVALUATION STUDY (Maximum funding/project period: $50,000/12

months) An evaluation study must include a systematic collection, analysis, and interpretation of data for the purpose of determining the impact of a program. The extent of the evaluation study could relate to the goals and objectives, policies and procedures, or programs regarding targeted groups. The evaluation study could also be used to determine the effectiveness and efficiency of a T/TO's program operations (*i.e.,* direct services, financial management, personnel, data collection and analysis, third-party billing, etc.), as well as to determine the appropriateness of new components of a T/TO's program operations that will assist efforts to improve Tribal health care delivery systems.

4. HEALTH MANAGEMENT STRUCTURE (Average funding/project period: $100,000/12 months; maximum funding/project period: $300,000/36 months) The first year funding level is limited to $150,000 for multi-year projects. The Health Management Structure component allows for implementation of systems to manage or organize PFSAs. Management structures include health department organizations, health boards, and financial management systems, including systems for accounting, personnel, third-party billing, medical records, management information systems, etc. This includes the design, improvement, and correction of management systems that address weaknesses identified through quality control measures, internal control reviews, and audit report findings under required financial audits and ISDEAA requirements.

For the minimum standards for the management systems used by a T/TO when carrying out Self-Determination contracts, please see 25 CFR part 900, Contracts Under the ISDEAA, Subpart F—''Standards for Tribal or Tribal Organization Management Systems,'' 900.35–900.60. For operational provisions applicable to carrying out Self-Governance compacts, please see 42 CFR part 137, Tribal Self-Governance, Subpart I,—''Operational Provisions,'' 137.160–137.220.

III. Eligibility Information

1. Eligibility

''Indian Tribes'' and ''Tribal Organizations'', as defined by the Indian Health Care Improvement Act (IHCIA), are eligible to apply for the TMG Program. The definitions for each entity type are outlined below. To be eligible for this funding opportunity for ''New Applicants Only,'' an applicant cannot be an existing TMG awardee under this program.

- A federally recognized Indian Tribe as defined by 25 U.S.C. 1603(14). The term ''Indian Tribe'' means any Indian Tribe, band, nation, or other organized group or community, including any Alaska Native village or group, or regional or village corporation as defined in or established pursuant to the Alaska Native Claims Settlement Act (85 Stat. 688) [43 U.S.C. 1601 *et seq.*], which is recognized as eligible for the special programs and services provided by the United States to Indians because of their status as Indians.
- A Tribal organization as defined by 25 U.S.C. 1603(26). The term ''Tribal organization'' has the meaning given the term in section 4 of the ISDEAA (25 U.S.C. 5304(l)): ''Tribal organization'' means the recognized governing body of any Indian Tribe; any legally established organization of Indians which is controlled, sanctioned, or chartered by such governing body or which is democratically elected by the adult members of the Indian community to be served by such organization and which includes the maximum participation of Indians in all phases of its activities: provided that, in any case where a contract is let or grant made to an organization to perform services benefiting more than one Indian Tribe, the approval of each such Indian Tribe shall be a prerequisite to the letting or making of such contract or grant. Applicant shall submit Tribal Resolutions from the Tribes to be served.

Please note that Tribes prohibited from contracting pursuant to the ISDEAA are not eligible for the TMG program. See section 424(a) of the Consolidated Appropriations Act, 2014, Public Law 113–76, as amended by section 428 of the Consolidated Appropriations Act, 2018, Public Law 115–141, and section 1201 of the Consolidated Appropriations Act, 2021, Public Law 116–260.

The Division of Grants Management (DGM) will notify any applicants deemed ineligible.

Note: Please refer to Section IV.2 (Application and Submission Information/Subsection 2, Content and Form of Application Submission) for additional proof of applicant status documents required, such as Tribal Resolutions, proof of nonprofit status, etc.

2. Cost Sharing or Matching

The IHS does not require matching funds or cost sharing for grants or cooperative agreements.

3. Other Requirements

Applications with budget requests that exceed the highest dollar amount outlined under Section II Award Information, Estimated Funds Available, or exceed the period of performance outlined under Section II Award Information, Period of Performance, are considered not responsive and will not be reviewed. The DGM will notify the applicant.

Additional Required Documentation

Tribal Resolution

The DGM must receive an official, signed Tribal Resolution prior to issuing a Notice of Award (NoA) to any Tribe or Tribal organization selected for funding. An applicant that is proposing a project affecting another Indian Tribe must include resolutions from all affected Tribes to be served. However, if an official signed Tribal Resolution cannot be submitted with the application prior to the application deadline date, a draft Tribal Resolution must be submitted with the application by the deadline date in order for the application to be considered complete and eligible for review. The draft Tribal Resolution is not in lieu of the required signed resolution but is acceptable until a signed resolution is received. If an application without a signed Tribal Resolution is selected for funding, the applicant will be contacted by the Grants Management Specialist (GMS) listed in this funding announcement and given 90 days to submit an official signed Tribal Resolution to the GMS. If the signed Tribal Resolution is not received within 90 days, the award will be forfeited.

Applicants organized with a governing structure other than a Tribal council may submit an equivalent document commensurate with their governing organization.

Proof of Nonprofit Status

Organizations claiming nonprofit status must submit a current copy of the 501(c)(3) Certificate with the application.

Additional Required Documentation for Specific TMG Project Types

A. Federally recognized Indian Tribes applying for technical assistance and/or training grants must provide a Tribal Resolution; or a designated Tribal Organization applying on behalf of the Indian Tribe and/or Tribes it intends to serve must also provide a Tribal Resolution.

B. Documentation for Priority I participation requires a copy of the **Federal Register** notice or letter from the Bureau of Indian Affairs verifying establishment of recognized Tribal status within the past 5 years. The date on the documentation must reflect that Federal recognition was received during or after March 2016.

C. Documentation for Priority II participation requires a copy of the most current transmittal letter and Attachment A from the Department of Health and Human Services (HHS), Office of Inspector General (OIG), National External Audit Review Center (NEAR). See ''Funding Priorities'' for more information. If an applicant is unable to provide a copy of the most recent transmittal letter or needs assistance with audit issues, information or technical assistance may be obtained by contacting the IHS Office of Finance and Accounting, Division of Audit by telephone at (301) 443–1270, or toll-free at the NEAR help line at (800) 732–0679 or (816) 426–7720. Recognized T/TOs not subject to Single Audit Act requirements must provide a financial statement identifying the Federal dollars received in the footnotes. The financial statement must also identify specific weaknesses/recommendations that will be addressed in the TMG proposal and that are related to 25 CFR part 900, subpart F—Standards for Tribal or Tribal Organization Management Systems.

D. Documentation of Consortium participation—If an applicant is a member of an eligible intertribal consortium, the Tribe must:

1. Identify the consortium.

2. Demonstrate that the Tribe's application does not duplicate or overlap any objectives of the consortium's application.

3. Identify all consortium member Tribes.

4. Identify if any of the consortium member Tribes intend to submit a TMG application of their own.

5. Demonstrate that the consortium's application does not duplicate or overlap any objectives of other consortium members who may be submitting their own TMG application.

Funding Priorities: The IHS has established the following funding priorities for TMG awards:

• PRIORITY I—Any Indian Tribe, or Tribal Organization representing that Indian Tribe, that has received Federal recognition (including restored, funded, or unfunded) within the past 5 years, specifically received during or after March 2016, will be considered Priority I.

• PRIORITY II—Indian Tribes and Tribal Organizations submitting a new application or a competing continuation application for the sole purpose of addressing audit material weaknesses will be considered Priority II. Priority II participation is only applicable to the Health Management Structure project type. For more information, see ''Eligible TMG Project Types, Maximum Funding Levels, and Project Periods,'' in Section II.

• PRIORITY III—Eligible Direct Service and T/TOs with a Title I ISDEAA contract with the IHS submitting a new application or a competing continuation application will be considered Priority III.

• PRIORITY IV—Eligible T/TOs with a Title V ISDEAA compact with the IHS submitting a new application or a competing continuation application will be considered Priority IV.

The funding of approved Priority I applicants will occur before the funding of approved Priority II applicants. Priority II applicants will be funded before approved Priority III applicants. Priority III applicants will be funded before approved Priority IV applicants. Funds will be distributed until depleted.

The following definitions are applicable to the PRIORITY II category:

Audit finding—deficiencies that the auditor is required by 45 CFR 75.516 to report in the schedule of findings and questioned costs.

Material weakness—''Statements on Auditing Standards 115'' defines material weakness as a deficiency, or combination of deficiencies, in internal control, such that there is a reasonable possibility that a material misstatement of the entity's financial statements will not be prevented, or detected and corrected on a timely basis.

Significant deficiency—''Statements on Auditing Standards 115,'' defines significant deficiency as a deficiency, or a combination of deficiencies, in internal control that is less severe than a material weakness, yet important enough to merit attention by those charged with governance.

The audit findings are identified in Attachment A of the transmittal letter received from the HHS/OIG/NEAR. Please identify the material weaknesses to be addressed by underlining the item(s) listed in Attachment A.

Indian Tribes and Tribal Organizations not subject to Single Audit Act requirements must provide a financial statement identifying the Federal dollars received in the footnotes. The financial statement should also identify specific weaknesses/recommendations that will be addressed in the TMG proposal and that are related to 25 CFR part 900, subpart F, Standards for Tribal and Tribal Organization Management Systems.

Note: A decision to award a TMG does not represent a determination from the IHS regarding the T/TO's eligibility to contract for a specific PFSA under the ISDEAA. An application for a TMG does not constitute a contract proposal.

IV. Application and Submission Information

Grants.gov uses a Workspace model for accepting applications. The Workspace consists of several online forms and three forms in which to upload documents—Project Narrative, Budget Narrative, and Other Documents. Give your files brief descriptive names. The filenames are key in finding specific documents during the objective review and in processing awards. Upload all requested and optional documents individually, rather than combining them into a package. Creating a package creates confusion when trying to find specific documents. Such confusion can contribute to delays in processing awards, and could lead to lower scores during the objective review.

1. Obtaining Application Materials

The application package and detailed instructions for this announcement are available at *https://www.Grants.gov.*

Please direct questions regarding the application process to *DGM@ihs.gov.*

2. Content and Form Application Submission

Mandatory documents for all applicants include:

• Application forms:

1. SF–424, Application for Federal Assistance.

2. SF–424A, Budget Information—Non-Construction Programs.

3. SF–424B, Assurances—Non-Construction Programs.

4. Project Abstract Summary form.

• Project Narrative (not to exceed 15 pages). See Section IV.2.A, Project Narrative for instructions.

• Budget Justification and Narrative (not to exceed 5 pages). See Section IV.2.B, Budget Narrative for instructions.

• One-page Timeframe Chart.

• Tribal Resolution(s) as described in Section III, Eligibility.

• Letters of Support from organization's Board of Directors (if applicable).

• 501(c)(3) Certificate (if applicable).

• Biographical sketches for all Key Personnel.

• Contractor/Consultant resumes or qualifications and scope of work.

• Disclosure of Lobbying Activities (SF–LLL), if applicant conducts reportable lobbying.
• Certification Regarding Lobbying (GG-Lobbying Form).
• Copy of current Negotiated Indirect Cost (IDC) rate agreement (required in order to receive IDC).
• Organizational Chart (optional).
• Documentation of current Office of Management and Budget (OMB) Financial Audit (if applicable).

Acceptable forms of documentation include:

1. Email confirmation from Federal Audit Clearinghouse (FAC) that audits were submitted; or
2. Face sheets from audit reports. Applicants can find these on the FAC website at *https://facdissem.census.gov/.*

Public Policy Requirements

All Federal public policies apply to IHS grants and cooperative agreements. Pursuant to 45 CFR 80.3(d), an individual shall not be deemed subjected to discrimination by reason of their exclusion from benefits limited by Federal law to individuals eligible for benefits and services from the IHS. See *https://www.hhs.gov/grants/grants/grants-policies-regulations/index.html.*

Requirements for Project and Budget Narratives

A. *Project Narrative:* This narrative should be a separate document that is no more than 15 pages and must: (1) have consecutively numbered pages; (2) use black font 12 points or larger (applicants may use 10 point font for tables); (3) be single-spaced; and (4) be formatted to fit standard letter paper (8-1/2 x 11 inches). Do not combine this document with any others.

Be sure to succinctly answer all questions listed under the evaluation criteria (refer to Section V.1, Evaluation Criteria) and place all responses and required information in the correct section noted below or they will not be considered or scored. If the narrative exceeds the overall page limit, the reviewers will be directed to ignore any content beyond the page limit. The 15-page limit for the narrative does not include the work plan, standard forms, Tribal Resolutions, budget, budget justifications, narratives, and/or other items. Page limits for each section within the project narrative are guidelines, not hard limits.

There are three parts to the narrative: Part 1—Program Information; Part 2—Program Planning and Evaluation; and Part 3—Program Report. See below for additional details about what must be included in the narrative.

The page limits below are for each narrative and budget submitted.

Part 1: Program Information (Limit—2 Pages)

Section 1: Needs.

Describe how the T/TO has determined the need to either enhance or develop Tribal management capability to either assume PFSAs or not in the interest of Self-Determination. Note the progression of previous TMG projects/awards if applicable.

Part 2: Program Planning and Evaluation (Limit—11 Pages)

Section 1: Program Plans.

Describe fully and clearly the direction the T/TO plans to take with the selected TMG Project type in addressing their health management infrastructure, including how the T/TO plans to demonstrate improved health and services to the community or communities it serves. Include proposed timelines.

Section 2: Program Evaluation.

Describe fully and clearly the improvements that will be made by the T/TO that will impact their management capability or prepare them for future improvements to their organization that will allow them to manage their health care system and identify the anticipated or expected benefits for the Tribe.

Part 3: Program Report (Limit—2 Pages)

Section 1: Describe your organization's significant program activities and accomplishments over the past 5 years associated with the goals of this announcement.

Please identify and describe significant program achievements associated with the delivery of quality health services. Provide a comparison of the actual accomplishments to the goals established for the project period, or if applicable, provide justification for the lack of progress.

B. Budget Narrative (Limit—5 Pages)

Provide a budget narrative that explains the amounts requested for each line item of the budget from the SF–424A (Budget Information for Non-Construction Programs) for the first year of the project. The applicant can submit with the budget narrative a more detailed spreadsheet than is provided by the SF–424A (the spreadsheet will not be considered part of the budget narrative). The budget narrative should specifically describe how each item will support the achievement of proposed objectives. Be very careful about showing how each item in the ''Other'' category is justified. Do NOT use the budget narrative to expand the project narrative.

3. Submission Dates and Times

Applications must be submitted through *Grants.gov* by 11:59 p.m. Eastern Time on the Application Deadline Date. Any application received after the application deadline will not be accepted for review. *Grants.gov* will notify the applicant via email if the application is rejected.

If technical challenges arise and assistance is required with the application process, contact *Grants.gov* Customer Support (see contact information at *https://www.Grants.gov*). If problems persist, contact Mr. Paul Gettys (*Paul.Gettys@ihs.gov*), Deputy Director, DGM, by telephone at (301) 443–2114. Please be sure to contact Mr. Gettys at least 10 days prior to the application deadline. Please do not contact the DGM until you have received a *Grants.gov* tracking number. In the event you are not able to obtain a tracking number, call the DGM as soon as possible.

The IHS will not acknowledge receipt of applications.

4. Intergovernmental Review

Executive Order 12372 requiring intergovernmental review is not applicable to this program.

5. Funding Restrictions

• Pre-award costs are allowable up to 90 days before the start date of the award provided the costs are otherwise allowable if awarded. Pre-award costs are incurred at the risk of the applicant.
• The available funds are inclusive of direct and indirect costs.
• Only one grant may be awarded per applicant.

6. Electronic Submission Requirements

All applications must be submitted via *Grants.gov*. Please use the *https://www.Grants.gov* website to submit an application. Find the application by selecting the ''Search Grants'' link on the homepage. Follow the instructions for submitting an application under the Package tab. No other method of application submission is acceptable.

If you cannot submit an application through *Grants.gov*, you must request a waiver prior to the application due date. This contact must be initiated prior to the application due date or your waiver request will be denied. Prior approval must be requested and obtained from Mr. Paul Gettys, Deputy Director, DGM. You must send a written waiver request to *DGM@ihs.gov* with a copy to *Paul.Gettys@ihs.gov.* The waiver request must be documented in writing (emails are acceptable) before submitting an application by some other method, and must include clear justification for the need to deviate from the required application submission process.

If the DGM approves your waiver request, you will receive a confirmation of approval email containing submission instructions. You must include a copy of the written approval with the application submitted to the DGM. Applications that do not include a copy of the signed waiver from the Deputy Director of the DGM will not be reviewed. The Grants Management Officer of the DGM will notify the applicant via email of this decision. Applications submitted under waiver must be received by the DGM no later than 5:00 p.m. Eastern Time on the Application Deadline Date. Late applications will not be accepted for processing. Applicants that do not register for both the System for Award Management (SAM) and *Grants.gov* and/or fail to request timely assistance with technical issues will not be considered for a waiver to submit an application via alternative method.

Please be aware of the following:

• Please search for the application package in *https://www.Grants.gov* by entering the Assistance Listing (CFDA) number or the Funding Opportunity Number. Both numbers are located in the header of this announcement.

• If you experience technical challenges while submitting your application, please contact *Grants.gov* Customer Support (see contact information at *https://www.Grants.gov*).

• Upon contacting *Grants.gov*, obtain a tracking number as proof of contact. The tracking number is helpful if there are technical issues that cannot be resolved and a waiver from the agency must be obtained.

• Applicants are strongly encouraged not to wait until the deadline date to begin the application process through *Grants.gov* as the registration process for SAM and *Grants.gov* could take up to 20 working days.

• Please follow the instructions on *Grants.gov* to include additional documentation that may be requested by this funding announcement.

• Applicants must comply with any page limits described in this funding announcement.

• After submitting the application, you will receive an automatic acknowledgment from *Grants.gov* that contains a *Grants.gov* tracking number. The IHS will not notify you that the application has been received.

System for Award Management (SAM)

Organizations that are not registered with SAM must access the SAM online registration through the SAM home page at *https://sam.gov.* Organizations in the U.S. will also need to provide an Employer Identification Number from the Internal Revenue Service that may take an additional 2–5 weeks to become active. Please see *SAM.gov* for details on the registration process and timeline. Registration with the SAM is free of charge but can take several weeks to process. Applicants may register online at *https://sam.gov.*

Unique Entity Identifier

Your *SAM.gov* registration now includes a Unique Entity Identifier (UEI), generated by *SAM.gov*, which replaces the DUNS number obtained from Dun and Bradstreet. *SAM.gov* registration no longer requires a DUNS number.

Check your organization's *SAM.gov* registration as soon as you decide to apply for this program. If your *SAM.gov* registration is expired, you will not be able to submit an application. It can take several weeks to renew it or resolve any issues with your registration, so do not wait.

Check your *Grants.gov* registration. Registration and role assignments in *Grants.gov* are self-serve functions. One user for your organization will have the authority to approve role assignments, and these must be approved for active users in order to ensure someone in your organization has the necessary access to submit an application.

The Federal Funding Accountability and Transparency Act of 2006, as amended (''Transparency Act''), requires all HHS awardees to report information on sub-awards. Accordingly, all IHS awardees must notify potential first-tier sub-awardees that no entity may receive a first-tier sub-award unless the entity has provided its UEI number to the prime awardee organization. This requirement ensures the use of a universal identifier to enhance the quality of information available to the public pursuant to the Transparency Act.

Additional information on implementing the Transparency Act, including the specific requirements for SAM, are available on the DGM Grants Management, Policy Topics web page at *https://www.ihs.gov/dgm/policytopics/.*

V. Application Review Information

Possible points assigned to each section are noted in parentheses. The project narrative and budget narrative should include only the first year of activities. The project narrative should be written in a manner that is clear to outside reviewers unfamiliar with prior related activities of the applicant. It should be well organized, succinct, and contain all information necessary for reviewers to fully understand the project. Attachments requested in the criteria do not count toward the page limit for the narratives. Points will be assigned to each evaluation criteria adding up to a total of 100 possible points. Points are assigned as follows:

1. Evaluation Criteria

A. Introduction and Need for Assistance (20 Points)

1. Describe the T/TO's current health operation. Include a list of programs and services that are currently provided (*e.g.,* federally funded, state funded, etc.), information regarding technologies currently used (*e.g.,* hardware, software, services, etc.), and identify the source(s) of technical support for those technologies (*i.e.,* Tribal staff, Area office IHS, vendor, etc.). Include information regarding whether the T/TO has a health department and/or health board and how long it has been operating.

2. Describe the population to be served by the proposed project. Include the total number of eligible IHS beneficiaries currently using the services.

3. Describe the geographic location of the proposed project, including any geographic barriers to health care users in the area to be served.

4. Identify all TMGs received since FY 2013, dates of funding, and a summary of project accomplishments. State how previous TMG funds facilitated the progression of health development relative to the current proposed project. (Copies of reports will not be accepted.)

5. Identify the eligible project type and priority group of the applicant.

6. Explain the need or reason for the proposed TMG project. Identify specific weaknesses and gaps in service or infrastructure that will be addressed by the proposal. Explain how these gaps and weaknesses will be assessed.

7. If the proposed TMG project includes information technology (*i.e.,* hardware, software, etc.), provide further information regarding measures that have occurred or will occur to ensure the proposed project will not create other gaps in services or infrastructure (*e.g.,* negatively affect or impact IHS interface capability, Government Performance and Results Act reporting requirements, contract reporting requirements, Information

Technology (IT) compatibility, etc.), if applicable.

8. Describe the effect of the proposed TMG project on current programs (*e.g.,* federally funded, state funded, etc.), and, if applicable, on current equipment (*e.g.,* hardware, software, services, etc.). Include the effect of the proposed project on planned or anticipated programs and equipment.

9. Address how the proposed TMG project relates to the purpose of the TMG Program by addressing the appropriate description that follows:

a. Identify whether the T/TO is an IHS Title I contractor. Address if the Self-Determination contract is a master contract of several programs or if individual contracts are used for each program. Include information regarding whether or not the T/TO participates in a consortium contract (*i.e.,* more than one Tribe participating in a contract). Address what programs are currently provided through those contracts and how the proposed TMG project will enhance the organization's capacity to manage the contracts currently in place.

b. Identify if the T/TO is not an IHS Title I contractor. Address how the proposed TMG project will enhance the organization's management capabilities, what programs and services the organization is currently seeking to contract, and an anticipated date for contract.

c. Identify if the T/TO is an IHS Title V compactor. Address when the T/TO entered into the compact and how the proposed project will further enhance the organization's management capabilities.

B. Project Objective(s), Work Plan, and Approach (40 Points)

1. The proposed project objectives must be:

a. measureable and (if applicable) quantifiable;

b. results-oriented;

c. time-limited.

Example: By installing new third-party billing software, the Tribe proposes to increase the number of claims processed by 15 percent within 12 months.

2. For each objective, address how the proposed TMG project will result in change or improvement in program operations or processes. Also, address what tangible products are expected from the project (*i.e.,* policies and procedures manual, health plan, etc.).

3. Address the extent to which the proposed project will build local capacity to provide, improve, or expand services that address the needs of the target population.

4. Submit a work plan in the Other Attachments that includes the following:

a. Provide action steps on a timeline for accomplishing the proposed project objectives.

b. Identify who will perform the action steps.

c. Identify who will supervise the action steps taken.

d. Identify tangible products that will be produced during and at the end of the proposed project.

e. Identify who will accept and/or approve work products during the duration of the proposed TMG project and at the end of the proposed project.

f. Include a description of any training activities proposed. This description will identify the target audience and training personnel.

g. Include work plan evaluation activities.

5. If consultants or contractors will be used during the proposed project, please complete the following information in their scope of work. (If consultants or contractors will not be used, please make note in this section):

a. Educational requirements.

b. Desired qualifications and work experience.

c. Expected work products to be delivered, including a timeline.

If potential consultants or contractors have already been identified, please upload a resume for each consultant or contractor in the Other Attachments in *Grants.gov*.

6. Describe updates that will be required for the continued success of the proposed TMG project (*i.e.,* revision of policies/procedures, upgrades, technical support, etc.). Include a timeline of anticipated updates and source of funding to conduct the update and/or maintenance.

C. Program Evaluation (20 Points)

Each proposed objective requires an evaluation activity (such as a logic model) to assess its progression and ensure completion. This should be included in the work plan.

Describe the proposal's plan to evaluate project processes and outcomes. Outcome evaluation relates to the results identified in the objectives. Process evaluation relates to the work plan and activities of the project.

1. For outcome evaluation, describe:

a. The criteria for determining whether each objective was met.

b. The data to be collected to determine whether the objective was met.

c. Data collection intervals.

d. Who will be responsible for collecting the data and their qualifications.

e. Data analysis method.

f. How the results will be used.

2. For process evaluation, describe:

a. The process for monitoring and assessing potential problems, then identifying quality improvements.

b. Who will be responsible for monitoring and managing project improvements based on results of ongoing process improvements and their qualifications.

c. Provide details with regards to the ways ongoing monitoring will be used to improve the project.

d. Describe any products, such as manuals or policies, that might be developed and how they might lend themselves to replication by others.

e. How the T/TO will document what is learned throughout the project period.

3. Describe any additional evaluation efforts planned after the grant period has ended.

4. Describe the ultimate benefit to the T/TO that is expected to result from this project. An example would be a T/TO's ability to expand preventive health services because of increased billing and third-party payments.

D. Organizational Capabilities, Key Personnel, and Qualifications (15 Points)

This section outlines the T/TO's capacity to complete the proposal outlined in the work plan. It includes the identification of personnel responsible for completing tasks and the chain of responsibility for completion of the proposed plan.

1. Provide the organizational structure of the T/TO.

2. Provide information regarding plans to obtain management systems if a T/TO does not have an established management system currently in place that complies with 25 CFR part 900, subpart F, Standards for Tribal or Tribal Organization Management Systems. State if management systems are already in place and how long the systems have been in place.

3. Describe the ability of the T/TO to manage the proposed project. Include information regarding similarly sized projects in scope and financial assistance as well as other grants and projects successfully completed.

4. Describe equipment (*e.g.,* fax machine, telephone, computer, etc.) and facility space (*i.e.,* office space) that will be available for use during the proposed project. Include information about any equipment not currently available that will be purchased through the grant.

5. List key project personnel and their titles in the work plan.

6. Provide the position descriptions and resumes for all key personnel as

Other Attachments in *Grants.gov*. The included position descriptions should: (1) clearly describe each position's duties; and (2) indicate desired qualifications and project associated experience. Each resume must include a statement indicating that the proposed key personnel is explicitly qualified to carry out the proposed project activities. If no current candidate for a position exists, please provide a statement to that effect in the Other Attachments.

7. If an individual is partially funded by this grant, indicate the percentage of his or her time to be allocated to the project and identify the resources used to fund the remainder of that individual's salary.

8. Address how the T/TO will sustain the proposal created positions after the grant expires. Please indicate if the project requires additional personnel (*i.e.,* IT support, etc.). If no additional personnel are required, please indicate that in this section.

E. Categorical Budget and Budget Justification (5 Points)

1. Provide a categorical budget for the first budget period.

2. If indirect costs are claimed, indicate and apply the current negotiated rate to the budget. Include a copy of the rate agreement in the Other Attachments.

3. Provide a narrative justification explaining why each categorical budget line item is necessary and relevant to the proposed project. Include sufficient cost and other details to facilitate the determination of cost allowability (*e.g.,* equipment specifications, etc.).

Additional documents can be uploaded as Other Attachments in *Grants.gov.* These can include:

- Work plan, logic model, and/or timeline for proposed objectives.
- Position descriptions for key staff.
- Resumes of key staff that reflect current duties.
- Consultant or contractor proposed scope of work and letter of commitment (if applicable).
- Current Indirect Cost Rate Agreement.
- Organizational chart.
- Map of area identifying project location(s).
- Additional documents to support narrative (*i.e.* data tables, key news articles, etc.).

2. Review and Selection

Each application will be prescreened for eligibility and completeness as outlined in the funding announcement. Applications that meet the eligibility criteria shall be reviewed for merit by the Objective Review Committee (ORC) based on evaluation criteria. Incomplete applications and applications that are not responsive to the administrative thresholds (budget limit, period of performance limit) will not be referred to the ORC and will not be funded. The program office will notify the applicant of this determination.

Applicants must address all program requirements and provide all required documentation.

3. Notifications of Disposition

All applicants will receive an Executive Summary Statement from the IHS Office of Direct Service and Contracting Tribes within 30 days of the conclusion of the ORC outlining the strengths and weaknesses of their application. The summary statement will be sent to the Authorizing Official identified on the face page (SF–424) of the application.

A. Award Notices for Funded Applications

The NoA is the authorizing document for which funds are dispersed to the approved entities and reflects the amount of Federal funds awarded, the purpose of the award, the terms and conditions of the award, the effective date of the award, the budget period, and period of performance. Each entity approved for funding must have a user account in GrantSolutions in order to retrieve the NoA. Please see the Agency Contacts list in Section VII for the systems contact information.

B. Approved but Unfunded Applications

Approved applications not funded due to lack of available funds will be held for 1 year. If funding becomes available during the course of the year, the application may be reconsidered.

Note: Any correspondence, other than the official NoA executed by an IHS grants management official announcing to the project director that an award has been made to their organization, is not an authorization to implement their program on behalf of the IHS.

VI. Award Administration Information

1. Administrative Requirements

Awards issued under this announcement are subject to, and are administered in accordance with, the following regulations and policies:

A. The criteria as outlined in this program announcement.

B. Administrative Regulations for Grants:

- Uniform Administrative Requirements, Cost Principles, and Audit Requirements for HHS Awards currently in effect or implemented during the period of award, other Department regulations and policies in effect at the time of award, and applicable statutory provisions. At the time of publication, this includes 45 CFR part 75, at *https://www.govinfo.gov/content/pkg/CFR-2021-title45-vol1/pdf/CFR-2021-title45-vol1-part75.pdf.*
- Please review all HHS regulatory provisions for Termination at 45 CFR 75.372, at the time of this publication located at *https://www.govinfo.gov/content/pkg/CFR-2021-title45-vol1/pdf/CFR-2021-title45-vol1-sec75-372.pdf.*

C. Grants Policy:

- HHS Grants Policy Statement, Revised January 2007, at *https://www.hhs.gov/sites/default/files/grants/grants/policies-regulations/hhsgps107.pdf.*

D. Cost Principles:

- Uniform Administrative Requirements for HHS Awards, ''Cost Principles,'' located at 45 CFR part 75 subpart E, at the time of this publication located at *https://www.govinfo.gov/content/pkg/CFR-2021-title45-vol1/pdf/CFR-2021-title45-vol1-part75-subpartE.pdf.*

E. Audit Requirements:

- Uniform Administrative Requirements for HHS Awards, Audit Requirements, located at 45 CFR part 75 subpart F, at the time of this publication located at *https://www.govinfo.gov/content/pkg/CFR-2021-title45-vol1/pdf/CFR-2021-title45-vol1-part75-subpartF.pdf.*

F. As of August 13, 2020, 2 CFR 200 was updated to include a prohibition on certain telecommunications and video surveillance services or equipment. This prohibition is described in 2 CFR 200.216. This will also be described in the terms and conditions of every IHS grant and cooperative agreement awarded on or after August 13, 2020.

2. Indirect Costs

This section applies to all recipients that request reimbursement of IDC in their application budget. In accordance with HHS Grants Policy Statement, Part II–27, the IHS requires applicants to obtain a current IDC rate agreement and submit it to the DGM prior to the DGM issuing an award. The rate agreement must be prepared in accordance with the applicable cost principles and guidance as provided by the cognizant agency or office. A current rate covers the applicable grant activities under the current award's budget period. If the current rate agreement is not on file with the DGM at the time of award, the IDC portion of the budget will be restricted. The restrictions remain in place until the current rate agreement is provided to the DGM. Per 45 CFR 75.414(f) Indirect (F&A) costs,

any non-Federal entity (NFE) [*i.e.,* applicant] that has never received a negotiated indirect cost rate, . . . may elect to charge a de minimis rate of 10 percent of modified total direct costs which may be used indefinitely. As described in Section 75.403, costs must be consistently charged as either indirect or direct costs, but may not be double charged or inconsistently charged as both. If chosen, this methodology once elected must be used consistently for all Federal awards until such time as the NFE chooses to negotiate for a rate, which the NFE may apply to do at any time.

Electing to charge a de minimis rate of 10 percent only applies to applicants that have never received an approved negotiated indirect cost rate from HHS or another cognizant Federal agency. Applicants awaiting approval of their indirect cost proposal may request the 10 percent de minimis rate. When the applicant chooses this method, costs included in the indirect cost pool must not be charged as direct costs to the grant.

Available funds are inclusive of direct and appropriate indirect costs. Approved indirect funds are awarded as part of the award amount, and no additional funds will be provided.

Generally, IDC rates for IHS grantees are negotiated with the Division of Cost Allocation at *https://rates.psc.gov/* or the Department of the Interior (Interior Business Center) at *https://ibc.doi.gov/ICS/tribal.* For questions regarding the indirect cost policy, please call the Grants Management Specialist listed under ''Agency Contacts'' or write to *DGM@ihs.gov.*

3. Reporting Requirements

The awardee must submit required reports consistent with the applicable deadlines. Failure to submit required reports within the time allowed may result in suspension or termination of an active grant, withholding of additional awards for the project, or other enforcement actions such as withholding of payments or converting to the reimbursement method of payment. Continued failure to submit required reports may result in the imposition of special award provisions and/or the non-funding or non-award of other eligible projects or activities. This requirement applies whether the delinquency is attributable to the failure of the awardee organization or the individual responsible for preparation of the reports. Per DGM policy, all reports must be submitted electronically by attaching them as a ''Grant Note'' in GrantSolutions. Personnel responsible for submitting reports will be required to obtain a login and password for GrantSolutions. Please use the form under the Recipient User section of *https://www.grantsolutions.gov/home/getting-started-request-a-user-account/.* Download the Recipient User Account Request Form, fill it out completely, and submit it as described on the web page and in the form.

The reporting requirements for this program are noted below.

A. Progress Reports

Program progress reports are required semi-annually. The progress reports are due within 30 days after the reporting period ends (specific dates will be listed in the NoA Terms and Conditions). These reports must include a brief comparison of actual accomplishments to the goals established for the period, a summary of progress to date or, if applicable, provide sound justification for the lack of progress, and other pertinent information as required. A final report must be submitted within 90 days of expiration of the period of performance.

B. Financial Reports

Federal Financial Reports are due 90 days after the end of each budget period, and a final report is due 90 days after the end of the period of performance.

Awardees are responsible and accountable for reporting accurate information on all required reports: the Progress Reports and the Federal Financial Report.

Failure to submit timely reports may result in adverse award actions blocking access to funds.

C. Federal Sub-Award Reporting System (FSRS)

This award may be subject to the Transparency Act sub-award and executive compensation reporting requirements of 2 CFR part 170.

The Transparency Act requires the OMB to establish a single searchable database, accessible to the public, with information on financial assistance awards made by Federal agencies. The Transparency Act also includes a requirement for recipients of Federal grants to report information about first-tier sub-awards and executive compensation under Federal assistance awards.

The IHS has implemented a Term of Award into all IHS Standard Terms and Conditions, NoAs, and funding announcements regarding the FSRS reporting requirement. This IHS Term of Award is applicable to all IHS grant and cooperative agreements issued on or after October 1, 2010, with a $25,000 sub-award obligation threshold met for any specific reporting period.

For the full IHS award term implementing this requirement and additional award applicability information, visit the DGM Grants Management website at *https://www.ihs.gov/dgm/policytopics/.*

D. Non-Discrimination Legal Requirements for Awardees of Federal Financial Assistance

Should you successfully compete for an award, recipients of Federal financial assistance (FFA) from HHS must administer their programs in compliance with Federal civil rights laws that prohibit discrimination on the basis of race, color, national origin, disability, age and, in some circumstances, religion, conscience, and sex (including gender identity, sexual orientation, and pregnancy). This includes ensuring programs are accessible to persons with limited English proficiency and persons with disabilities. The HHS Office for Civil Rights provides guidance on complying with civil rights laws enforced by HHS. Please see *https://www.hhs.gov/civil-rights/for-providers/provider-obligations/index.html* and *https://www.hhs.gov/civil-rights/for-individuals/nondiscrimination/index.html.*

• Recipients of FFA must ensure that their programs are accessible to persons with limited English proficiency. For guidance on meeting your legal obligation to take reasonable steps to ensure meaningful access to your programs or activities by limited English proficiency individuals, see *https://www.hhs.gov/civil-rights/for-individuals/special-topics/limited-english-proficiency/fact-sheet-guidance/index.html* and *https://www.lep.gov.*

• For information on your specific legal obligations for serving qualified individuals with disabilities, including reasonable modifications and making services accessible to them, see *https://www.hhs.gov/civil-rights/for-individuals/disability/index.html.*

• Health and education programs funded by the HHS must be administered in an environment free of sexual harassment. See *https://www.hhs.gov/civil-rights/for-individuals/sex-discrimination/index.html.*

• For guidance on administering your program in compliance with applicable Federal religious nondiscrimination laws and applicable Federal conscience protection and associated anti-discrimination laws, see *https://www.hhs.gov/conscience/conscience-protections/index.html* and *https://*

www.hhs.gov/conscience/religious-freedom/index.html.

E. Federal Awardee Performance and Integrity Information System (FAPIIS)

The IHS is required to review and consider any information about the applicant that is in the FAPIIS at *https://www.fapiis.gov/fapiis/#/home* before making any award in excess of the simplified acquisition threshold (currently $250,000) over the period of performance. An applicant may review and comment on any information about itself that a Federal awarding agency previously entered. The IHS will consider any comments by the applicant, in addition to 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 45 CFR 75.205.

As required by 45 CFR part 75 Appendix XII of the Uniform Guidance, NFEs are required to disclose in FAPIIS any information about criminal, civil, and administrative proceedings, and/or affirm that there is no new information to provide. This applies to NFEs that receive Federal awards (currently active grants, cooperative agreements, and procurement contracts) greater than $10 million for any period of time during the period of performance of an award/project.

Mandatory Disclosure Requirements

As required by 2 CFR part 200 of the Uniform Guidance, and the HHS implementing regulations at 45 CFR part 75, the IHS must require an NFE or an applicant for a Federal award to disclose, in a timely manner, in writing to the IHS or pass-through entity all violations of Federal criminal law involving fraud, bribery, or gratuity violations potentially affecting the Federal award.

All applicants and recipients must disclose in writing, in a timely manner, to the IHS and to the HHS OIG all information related to violations of Federal criminal law involving fraud, bribery, or gratuity violations potentially affecting the Federal award. 45 CFR 75.113.

Disclosures must be sent in writing to: U.S. Department of Health and Human Services, Indian Health Service, Division of Grants Management, Attn: Marsha Brookins, Director, 5600 Fishers Lane, Mail Stop: 09E70, Rockville, MD 20857, (Include ''Mandatory Grant Disclosures'' in subject line), Office: (301) 443–4750, Fax: (301) 594–0899, email: *DGM@ihs.gov* and U.S. Department of Health and Human Services, Office of Inspector General, Attn: Mandatory Grant Disclosures, Intake Coordinator, 330 Independence Avenue SW, Cohen Building, Room 5527, Washington, DC 20201, URL: *https://oig.hhs.gov/fraud/report-fraud/*, (Include ''Mandatory Grant Disclosures'' in subject line), Fax: (202) 205–0604 (Include ''Mandatory Grant Disclosures'' in subject line) or email: *MandatoryGranteeDisclosures@oig.hhs.gov*.

Failure to make required disclosures can result in any of the remedies described in 45 CFR 75.371 Remedies for noncompliance, including suspension or debarment (see 2 CFR part 180 and 2 CFR part 376).

VII. Agency Contacts

1. Questions on the programmatic issues may be directed to: Terri Schmidt, Director, Office of Direct Service and Contracting Tribes, Indian Health Service, 5600 Fishers Lane, Mail Stop: 08E17, Rockville, MD 20857, Phone: (301) 443–1104, email: *terri.schmidt@ihs.gov*.

2. Questions on grants management and fiscal matters may be directed to: Sheila A.L. Miller, Grants Management Specialist, Indian Health Service, Division of Grants Management, 5600 Fishers Lane, Mail Stop: 09E70, Rockville, MD 20857, Phone: (240) 535–9308, email: *sheila.miller@ihs.gov*.

3. Questions on systems matters may be directed to: Paul Gettys, Deputy Director, Indian Health Service, Division of Grants Management, 5600 Fishers Lane, Mail Stop: 09E70, Rockville, MD 20857, Phone: (301) 443–2114, email: *Paul.Gettys@ihs.gov*.

VIII. Other Information

The Public Health Service strongly encourages all grant, cooperative agreement, and contract recipients to provide a smoke-free workplace and promote the non-use of all tobacco products. In addition, Public Law 103–227, the Pro-Children Act of 1994, prohibits smoking in certain facilities (or in some cases, any portion of the facility) in which regular or routine education, library, day care, health care, or early childhood development services are provided to children. This is consistent with the HHS mission to protect and advance the physical and mental health of the American people.

P. Benjamin Smith,

Deputy Director, Indian Health Service.

[FR Doc. 2022–26480 Filed 12–5–22; 8:45 am]

BILLING CODE 4165–16–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Aging; Notice of Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of a meeting of the National Advisory Council on Aging.

The meeting will be open to the public as indicated below, with attendance limited to space available. Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should notify the Contact Person listed below in advance of the meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Advisory Council on Aging.

Date: January 18–19, 2023.

Closed: January 18, 2023, 3:00 p.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute on Aging, Gateway Building, 7201 Wisconsin Avenue, Bethesda, MD 20892 (Virtual Meeting).

Open: January 19, 2023, 10:00 a.m. to 2:00 p.m.

Agenda: Call to order and report from the Director; Discussion of future meeting dates; Consideration of minutes of last meeting; Reports from Task Force on Minority Aging Research, Working Group on Program; Council Speaker; Program Highlights.

Place: National Institute on Aging, Gateway Building, 7201 Wisconsin Avenue, Bethesda, MD 20892 (Virtual Meeting).

Closed: January 19, 2023, 2:00 p.m. to 2:30 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute on Aging, Gateway Building, 7201 Wisconsin Avenue, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Kenneth Santora, Director, Office of Extramural Activities, National Institute on Aging, National Institutes of Health, Gateway Building, 7201 Wisconsin Avenue, Bethesda, MD 20814, (301) 496–9322, *ksantora@nih.gov.*

Information is also available on the Institute's/Center's home page: *www.nia.nih.gov/about/naca,* where an agenda and any additional information for the meeting will be posted when available.

(Catalogue of Federal Domestic Assistance Program Nos. 93.866, Aging Research, National Institutes of Health, HHS)

Dated: December 1, 2022.

Miguelina Perez,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2022–26467 Filed 12–5–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of General Medical Sciences; Notice of Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of General Medical Sciences Special Emphasis Panel; Review of PRAT applications.

Date: March 7, 2023.

Time: 10:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, National Institute of General Medical Sciences, Natcher Building, 45 Center Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Lee Warren Slice, Ph.D., Scientific Review Officer, Office of Scientific Review, National Institute of General Medical Sciences, National Institutes of Health, 45 Center Drive, Room 3AN12, Bethesda, MD 20892, 301–435–0807, *slicelw@mail.nih.gov*.

(Catalogue of Federal Domestic Assistance Program Nos. 93.375, Minority Biomedical Research Support; 93.821, Cell Biology and Biophysics Research; 93.859, Pharmacology, Physiology, and Biological Chemistry Research; 93.862, Genetics and Developmental Biology Research; 93.88, Minority Access to Research Careers; 93.96, Special Minority Initiatives; 93.859, Biomedical Research and Research Training, National Institutes of Health, HHS)

Dated: November 30, 2022.

Miguelina Perez,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2022–26431 Filed 12–5–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Prospective Grant of an Exclusive Patent License: Use and Development of RAB13 and NET1 Targeting Antisense Oligonucleotides in the Treatment of Cancer

AGENCY: National Institutes of Health, HHS.

ACTION: Notice.

SUMMARY: The National Cancer Institute, an institute of the National Institutes of Health, Department of Health and Human Services, is contemplating the grant of an Exclusive Patent License to practice the inventions embodied in the U.S. Patents and Patent Applications listed in the Supplementary Information section of this notice to Drug Development and Filing Consulting, LLC located in Maryland, USA.

DATES: Only written comments and/or applications for a license which are received by the National Cancer Institute's Technology Transfer Center on or before December 21, 2022 will be considered.

ADDRESSES: Requests for copies of the patent application, inquiries, and comments relating to the contemplated an Exclusive Patent License should be directed to: Suna Gulay French, Technology Transfer Manager, Telephone: (240)-276–7424; Email: *suna.gulay@nih.gov*.

SUPPLEMENTARY INFORMATION:

Intellectual Property

1. United States Provisional Patent Application No. 62/966,204, filed January 27, 2020 and entitled ''RAB13 and NET1 Antisense Oligonucleotides to Treat Metastatic Cancer'' [HHS Ref. No. E–041–2020–0–US–01];

2. PCT Patent Application No. PCT/US2021/015053, filed January 26, 2021 and entitled ''RAB13 and NET1 Antisense Oligonucleotides to Treat Metastatic Cancer'' [HHS Ref. No. E–041–2020–0–PCT–02]; and

3. United States Patent Application No. 17/792,507, filed July 13, 2022 and entitled ''Antisense Oligos that Block Cancer Cell Migration and Invasion'' [HHS Ref. No. E–041–2020–0–US–03].

The patent rights in these inventions have been assigned and/or exclusively licensed to the government of the United States of America.

The prospective exclusive license territory may be the United States only and the field of use may be limited to: ''Use and development of RAB13 and NET1 targeting antisense oligonucleotides in treatment of breast cancer, ovarian cancer, cervical cancer and head and neck cancer in humans.''

This technology discloses RAB13 and NET1 targeting antisense oligonucleotides (ASOs) for use in targeted cancer therapy. These ASOs bind to the 3′-untranslated regions of RAB13 and NET1 mRNAs and prevent the localization of these mRNAs to cellular protrusions involved in motility. These ASOs reduce cell motility and migration in vitro. Due to this reduction in cell motility and migration, these ASOs are expected to have uses in the treatment of metastatic cancers.

This notice is made in accordance with 35 U.S.C. 209 and 37 CFR part 404. The prospective exclusive license will be royalty bearing, and the prospective exclusive license may be granted unless within fifteen (15) days from the date of this published notice, the National Cancer Institute receives written evidence and argument that establishes that the grant of the license would not be consistent with the requirements of 35 U.S.C. 209 and 37 CFR part 404.

In response to this Notice, the public may file comments or objections. Comments and objections, other than those in the form of a license application, will not be treated confidentially, and may be made publicly available.

License applications submitted in response to this Notice will be presumed to contain business confidential information and any release of information in these license applications will be made only as required and upon a request under the Freedom of Information Act, 5 U.S.C. 552.

Dated: November 30, 2022.

Richard U. Rodriguez,

Associate Director, Technology Transfer Center, National Cancer Institute.

[FR Doc. 2022–26430 Filed 12–5–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of General Medical Sciences; Notice of Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended, notice is hereby given of the following meeting. The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: NIGMS Initial Review Group Training and Workforce Development Study Section—C Review of IRACDA, B2B and B2D Applications.

Date: February 24, 2023.

Time: 10:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health National Institute of General Medical Sciences, Natcher Building, 45 Center Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: Sonia Ivette Ortiz-Miranda, Ph.D., Scientific Review Officer, National Institute of General Medical Sciences, National Institutes of Health, Bethesda, MD 20892, (301) 594–0534, *sonia.ortiz-miranda@nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.375, Minority Biomedical Research Support; 93.821, Cell Biology and Biophysics Research; 93.859, Pharmacology, Physiology, and Biological Chemistry Research; 93.862, Genetics and Developmental Biology Research; 93.88, Minority Access to Research Careers; 93.96, Special Minority Initiatives; 93.859, Biomedical Research and Research Training, National Institutes of Health, HHS)

Dated: November 30, 2022.

Miguelina Perez,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2022–26432 Filed 12–5–22; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HOMELAND SECURITY

[Docket No. DHS–2022-0057]

Homeland Security Advisory Council; Meetings

AGENCY: Office of Partnership and Engagement (OPE), Department of Homeland Security (DHS).

ACTION: Amendment of notice; partial closure.

SUMMARY: On November 22, 2022, the Department of Homeland Security (DHS) published a notice in the **Federal Register** announcing that the Homeland Security Advisory Council (HSAC) will hold a public and virtual meeting on Tuesday, December 6, 2022. This notice amends that prior notice. The meeting will now be partially closed from 3:25 p.m. to 4 p.m. EDT.

DATES: The document published at 87 FR 71348 on November 22, 2022 is amended as of November 30, 2022.

ADDRESSES: The HSAC meeting will be held at the Federal Emergency Management Agency (FEMA) headquarters in Washington, DC Members of the public interested in participating may do so via teleconference by following the process outlined below. The public will be in listen-only mode except for the public comment portion of the meeting. Written comments can be submitted from November 28, 2022 to December 6, 2022. Comments must be identified by Docket No. DHS–2022–0056 and may be submitted by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Email: HSAC@hq.dhs.gov.* Include Docket No. DHS–2022–0056 in the subject line of the message.
- *Mail:* Rebecca Sternhell, Executive Director of the Homeland Security Advisory Council, Office of Partnership and Engagement, Mailstop 0385, Department of Homeland Security, 2707 Martin Luther King Jr Ave SE, Washington, DC 20528.

Instructions: All submissions received must include the words ''Department of Homeland Security'' and ''DHS–2022–0056,'' the docket number for this action. Comments received will be posted without alteration at *http://www.regulations.gov,* including any personal information provided. You may wish to review the Privacy and Security Notice found via a link on the homepage of *www.regulations.gov.*

Docket: For access to the docket to read comments received by the Council, go to *http://www.regulations.gov,* search ''DHS–2022–0056,'' ''Open Docket Folder'' to view the comments.

FOR FURTHER INFORMATION CONTACT: Rebecca Sternhell at 202–891–2876 or *HSAC@hq.dhs.gov.*

SUPPLEMENTARY INFORMATION: Notice of this meeting is given under Section 10(a) of the Federal Advisory Committee Act (FACA), Public Law 92–463 (5 U.S.C. Appendix), which requires each FACA committee meeting to be open to the public unless the President, or the head of the agency to which the advisory committee reports, determines that a portion of the meeting may be closed to the public in accordance with 5 U.S.C. 552b(c).

The HSAC provides organizationally independent, strategic, timely, specific, actionable advice, and recommendations to the Secretary of Homeland Security on matters related to homeland security. The Council consists of senior executives from government, the private sector, academia, law enforcement, and non-governmental organizations. The open session will include: (1) Remarks from Senior DHS leaders, (2) introduction and swearing in of new members, (3) updates from new subcommittees, and (4) receipt of, deliberation on, and vote on the draft report from the Customer Experience and Service Delivery Subcommittee that was tasked on May 18, 2022.

The Council will meet in a closed session from 3:25 p.m. to 4 p.m. ET to participate in a sensitive discussion with DHS Senior Leadership regarding DHS operations. *Basis for Partial Closure:* In accordance with Section 10(d) of FACA, the Secretary of Homeland Security has determined this meeting must be closed during this session as the disclosure of the information relayed would be detrimental to the public interest for the following reasons:

The Council will participate in a sensitive operational discussion containing For Official Use Only and Law Enforcement Sensitive information. This discussion will include information regarding threats facing the United States and how DHS plans to address those threats. The session is closed pursuant to 5 U.S.C. 552b(c)(9)(B) because the disclosure of this information could significantly frustrate implementation of proposed agency actions.

Members of the public will be in listen-only mode except during the public comment session. Members of the public may register to participate in this Council meeting via teleconference under the following procedures. Each individual must provide their full legal name and email address no later than 5 p.m. ET on Friday, December 2, 2022 to Rebecca Sternhell of the Council via email to *HSAC@hq.dhs.gov* or via phone at 202–891–2876. Members of the public who have registered to participate will be provided the conference call after the closing of the public registration period and prior to the start of the meeting.

For information on services for individuals with disabilities, or to request special assistance, please email *HSAC@hq.dhs.gov* by 5 p.m. ET on December 2, 2022 or call 202–891–2876. The HSAC is committed to ensuring all participants have equal access regardless of disability status. If you require a reasonable accommodation due to a disability to fully participate, please contact Rebecca Sternhell at 202–891–2876 or *HSAC@hq.dhs.gov* as soon as possible.

Dated: November 30, 2022.

Rebecca Sternhell,

Executive Director, Homeland Security Advisory Council, Department of Homeland Security.

[FR Doc. 2022–26436 Filed 12–5–22; 8:45 am]

BILLING CODE P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–7056–N–54; OMB Control No. 2502–0267]

60-Day Notice of Proposed Information Collection: Section 202 Supportive Housing for the Elderly Application Submission Requirements

AGENCY: Office of the Assistant Secretary for Housing—Federal Housing Commissioner, HUD.

ACTION: Notice.

SUMMARY: HUD is seeking approval from the Office of Management and Budget (OMB) for the information collection described below. In accordance with the Paperwork Reduction Act, HUD is requesting comment from all interested parties on the proposed collection of information. The purpose of this notice is to allow for 60 days of public comment.

DATES: *Comments Due Date:* February 6, 2023.

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB Control Number and should be sent to: Colette Pollard, Reports Management Officer, REE, Department of Housing and Urban Development, 451 7th Street SW, Room 4176, Washington, DC 20410–5000; telephone 202–402–3400 (this is not a toll-free number) or email at *Colette.Pollard@hud.gov* for a copy of the proposed forms or other available information. HUD welcomes and is prepared to receive calls from individuals who are deaf or hard of hearing, as well as individuals with speech and 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.*

FOR FURTHER INFORMATION CONTACT: Colette Pollard, Reports Management Officer, REE, Department of Housing and Urban Development, 451 7th Street SW, Washington, DC 20410; email Colette Pollard at *Colette.Pollard@hud.gov* or telephone 202–402–3400. 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 and 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.*

Copies of available documents submitted to OMB may be obtained from Ms. Pollard.

SUPPLEMENTARY INFORMATION: This notice informs the public that HUD is seeking approval from OMB for the information collection described in Section A.

A. Overview of Information Collection

Title of Information Collection: Section 202 Supportive Housing for the Elderly.

OMB Approval Number: 2502–0267.

OMB Expiration Date: 10/31/2023.

Type of Request: Extension of a currently approved collection.

Form Number: Form SF–424, Form HUD–92015–CA, Form HUD–2530, Form HUD–2880, Form HUD–2993, Form HUD–92041, Form HUD–92042, Standard Form LLL.

Description of the need for the information and proposed use: This information collection is necessary to the Department to assist HUD in determining applicant eligibility and ability to develop housing for the elderly within statutory and program criteria. A thorough evaluation of an applicant's submission is necessary to protect the Government's financial interest. Under the new appropriation, the Section 202 program was redesigned to (1) strategically target funds to the most vulnerable elderly persons with the greatest unmet housing needs, and (2) select the most effective sponsors that could achieve positive outcomes in the most expeditious manner.

Respondents: Eligible applicants and any co-sponsors must be private, nonprofit organizations and nonprofit consumer cooperatives with tax exempt status under Internal Revenue Service code.

Estimated Number of Respondents: 150.

Estimated Number of Responses: 13,150.

Frequency of Response: Annual, dependent on new Congressional appropriation.

Average Hours per Response: 40.

Total Estimated Burden: 5,295.

B. Solicitation of Public Comment

This notice is soliciting comments from members of the public and affected parties concerning the collection of information described in Section A on the following:

(1) 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) The accuracy of the agency's estimate of the burden 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 those who are to respond; including through the use of appropriate automated collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses.

HUD encourages interested parties to submit comment in response to these questions.

C. Authority

Section 3507 of the Paperwork Reduction Act of 1995, 44 U.S.C. Chapter 35.

Jeffrey D. Little,

General Deputy Assistant Secretary, Office of Housing.

[FR Doc. 2022–26451 Filed 12–5–22; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–7056–N–47]

60-Day Notice of Proposed Information Collection: Office of Housing Counseling—Agency Performance Review, OMB Control No.: 2502–0574

AGENCY: Office of the Assistant Secretary for Housing—Federal Housing Commissioner, HUD.

ACTION: Notice.

SUMMARY: HUD is seeking approval from the Office of Management and Budget (OMB) for the information collection described below. In accordance with the Paperwork Reduction Act, HUD is requesting comment from all interested parties on the proposed collection of

information. The purpose of this notice is to allow for 60 days of public comment.

DATES: *Comments Due Date:* February 6, 2023.

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB Control Number and should be sent to: Colette Pollard, Reports Management Officer, REE, Department of Housing and Urban Development, 451 7th Street SW, Room 4176, Washington, DC 20410–5000; telephone 202–402–3400 (this is not a toll-free number) or email at *Colette.Pollard@hud.gov* for a copy of the proposed forms or other available information. 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.*

FOR FURTHER INFORMATION CONTACT: Colette Pollard, Reports Management Officer, QDAM, Department of Housing and Urban Development, at 451 7th Street SW, Washington, DC 20410; email at *Colette.Pollard@hud.gov* or telephone at 202–402–3400. 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.* Copies of available documents submitted to OMB may be obtained from Ms. Pollard.

SUPPLEMENTARY INFORMATION: This notice informs the public that HUD is seeking approval from OMB for the information collection described in Section A.

A. Overview of Information Collection

Title of Information Collection: Office of Housing Counseling—Agency Performance Review.

OMB Approval Number: 2502–0574.

OMB Expiration Date: August 31, 2024.

Type of Request: Revision of a currently approved collection.

Form Number: HUD–9910, Office of Housing Counseling—Agency Performance Review.

Description of the Need for the Information and Proposed Use: The revisions to the currently approved collection are needed to ensure the document complies with the requirements of an OIG audit that found the collection was not in compliance with 24 CFR 214.3 and 2 CFR 200.501, Audit requirements. The information is used to assist HUD in evaluating the managerial and financial capacity of organizations to sustain operations sufficient to implement HUD-approved housing counseling programs. The collection of information assists HUD in reducing its own risks from fraudulent activities or supporting inefficient or ineffective housing counseling programs. Since HUD publishes a web list of HUD-approved Housing Counseling Agencies and maintains a toll-free housing counseling hotline, performance reviews help HUD ensure that individuals seeking assistance from these approved agencies will receive high quality services.

HUD uses performance reviews to ascertain the professional and management capacity of HUD-approved housing counseling agencies to provide adequate housing counseling services necessary to comply with the requirements of the Housing and Urban Development Act and to ensure that grant-funded organizations comply with HUD and OMB administrative and financial regulations. If this information is not collected, HUD will be unable to effectively monitor the Housing Counseling Program to guard against waste, fraud, abuse, or inappropriate program practices. This collection provides the means to meet that obligation.

Respondents: Not-for-profit institutions; State, Local or Tribal Government.

Estimated Number of Respondents: 353.

Estimated Number of Responses: 353.

Frequency of Response: 1 per agency performance review.

Average Hours per Response: 9.5.

Total Estimated Burden: 3,354 hours.

B. Solicitation of Public Comment

This notice is soliciting comments from members of the public and affected parties concerning the collection of information described in Section A on the following:

(1) 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) The accuracy of the agency's estimate of the burden 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 those who are to respond, including through the use of appropriate automated collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses.

HUD encourages interested parties to submit comment in response to these questions.

C. Authority

Section 3507 of the Paperwork Reduction Act of 1995, 44 U.S.C. chapter 35.

Jeffrey D. Little,

General Deputy Assistant Secretary for Housing.

[FR Doc. 2022–26453 Filed 12–5–22; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–7056–N–42; OMB Control No. 2502–0587]

60-Day Notice of Proposed Information Collection: Section 8 Renewal Policy Guidebook

AGENCY: Office of the Assistant Secretary for Housing—Federal Housing Commissioner, HUD.

ACTION: Notice.

SUMMARY: HUD is seeking approval from the Office of Management and Budget (OMB) for the information collection described below. In accordance with the Paperwork Reduction Act, HUD is requesting comment from all interested parties on the proposed collection of information. The purpose of this notice is to allow for 60 days of public comment.

DATES: Comments Due Date: February 6, 2023.

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB Control Number and should be sent to: Colette Pollard, Reports Management Officer, REE, Department of Housing and Urban Development, 451 7th Street SW, Room 4176, Washington, DC 20410–5000; telephone 202–402–3400 (this is not a toll-free number) or email at *Colette.Pollard@hud.gov* for a copy of the proposed forms or other available information. HUD welcomes and is prepared to receive calls from individuals who are deaf or hard of hearing, as well as individuals with speech and 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.*

FOR FURTHER INFORMATION CONTACT: Colette Pollard, Reports Management Officer, REE, Department of Housing and Urban Development, 451 7th Street SW, Washington, DC 20410; email Colette Pollard at *Colette.Pollard@hud.gov* or telephone 202–402–3400. 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 and 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.*

Copies of available documents submitted to OMB may be obtained from Ms. Pollard.

A. Overview of Information Collection

Title of information collection: Section 8 Renewal Policy Guidebook.

OMB approval number: 2502–0587.

OMB expiration date: November 30, 2020.

Type of request: Reinstatement, with change, of previously approved collection for which approval has expired.

Form numbers:

1. Housing Assistance Payments Contract: HUD–52522a; HUD–52522b
2. Assignment, Assumption, and Amendment of Section 8 Housing Assistance Payments (HAP) Contract: HUD–5988 *(new)*
3. Use Agreement: HUD–90055
4. Rent Comparability Grid: HUD–92273–S8
5. Project-Based Section 8 Housing Assistance Payments: Addendum to Renewal Contract Under Option One or Option Two for Capital Repairs and/or Acquisition Costs: HUD–93181
6. Project-Based Section 8 Housing Assistance Payments: Addendum to Renewal Contract Under Option One or Option Two for Capital Repairs and/or Acquisition—Post-Rehabilitation Rents at Closing: HUD–93182
7. Rider to Original Section 8 Housing Assistance Payments Contract: HUD–93184
8. Amendment to Project-Based Section 8 Housing Assistance Payments Contract Pursuant to Section 8(bb)(1) of the United States Housing Act of 1937: HUD–93185a; HUD–93185b
9. Contract Renewal Request Form: HUD–9624
10. OCAF Rent Adjustment Worksheet: HUD–9625
11. Letters to Owners/Agents: HUD–9626
12. Letters to Owners/Agents: HUD–9627
13. Request to Renew Using Non–Section 8 Units in the Section 8 Project as a Market Rent Ceiling: HUD–9629
14. Request to Renew Using Fair Market Rents (FMRs) as Market Ceiling: HUD–9630
15. Sample Use Agreement: HUD–9634
16. Projects Preparing a Budget-Based Rent Increase: HUD–9635
17. Project-Based Section 8 Housing Assistance Payments Basic Renew Contract—One-Year Term: HUD–9636
18. Project-Based Section 8 Housing Assistance Payments Basic Renew Contract—Multi-Year Term: HUD–9637
19. Project-Based Section 8 Housing Assistance Payments Renewal Contract for Mark-Up-To-Market Project: HUD–9638
20. Project-Based Section 8 Housing Assistance Payments Preservation Renewal Contract: HUD–9639
21. Project-Based Section 8 Housing Assistance Payments Interim (Full) Mark-To-Market Renewal Contract: HUD–9640
22. Project-Based Section 8 Housing Assistance Payments Interim (Lite) Mark-To-Market Renewal Contract: HUD–9641
23. Project-Based Section 8 Housing Assistance Payments Full Mark-To-Market Renewal Contract: HUD–9642
24. Project-Based Section 8 Housing Assistance Payments Watch List Renewal Contract: HUD–9643
25. Project-Based Assistance Housing Assistance Payments Contract For Previous Mod Rehab Projects: HUD–9644
26. Housing Assistance Payments Program Housing Finance & Development Agencies Extension Amendment to Old Regulation State Agency Housing Assistance Payments Contract: HUD–9647
27. Project-Based Section 8 Contract Administration Consent to Assignment of HAP Contract as Security for Freddie Mac Financing: HUD–9648a
28. Project-Based Section 8 Contract Administration Consent to Assignment of HAP Contract to FNMA as Security for FNMA Credit Enhancement: HUD–9648d
29. Project-Based Section 8 Contract Administration Consent to Assignment of HAP Contract as Security for Financing: HUD–9649
30. Consent to Assignment of Senior Preservation Rental Assistance Contracts (SPRAC) as Security for Financing: HUD–9649a
31. Project-Based Section 8 Contract Administration Consent to Assignment of HAP Contract as Security for FNMA Financing: HUD–9651

Information collection	Number of respondents	Total annual responses	Burden hours per response	Total annual burden hrs.	Hourly cost to public	Total annual cost to public	Hourly cost to government	Total annual cost to government
Housing Assistance Payments Contract (HUD–52522a and b)	20	20	0.50	10	$39.72	$397.20	$51.18	$511.80
Assignment, Assumption, and Amendment of Section 8 Housing Assistance Payments (HAP) Contract (HUD–5988)	3,555	3,555	0.50	1,778	39.72	70,602.30	51.18	90,972.45
Section 8 Use Agreement (HUD–90055)	75	75	0.50	38	39.72	1,489.50	51.18	1,919.25
Rent Comparability Grid (HUD–92273–S8)	950	950	1.00	950	39.72	37,734.00	51.18	48,621.00
Project-Based Section 8 Housing Assistance Payments: Addendum to Renewal Contract Under Option One or Option Two for Capital Repairs and/or Acquisition Costs (HUD–93181)	50	50	0.50	25	39.72	993.00	51.18	1,279.50
Project-Based Section 8 Housing Assistance Payments: Addendum to Renewal Contract Under Option One or Option Two for Capital Repairs and/or Acquisition—Post-Rehabilitation Rents at Closing (HUD–93182)	150	150	0.50	75	39.72	2,979.00	51.18	3,838.50
Rider to Original Section 8 Housing Assistance Payments Contract (HUD–93184)	20	20	0.50	10	39.72	397.20	51.18	511.80

Information collection	Number of respondents	Total annual responses	Burden hours per response	Total annual burden hrs.	Hourly cost to public	Total annual cost to public	Hourly cost to government	Total annual cost to government
Amendment to Project-Based Section 8 Housing Assistance Payments Contract [Contract A1] Pursuant to Section 8(bb)(1) of the United States Housing Act of 1937 (HUD–93185a)	25	25	0.50	13	39.72	496.50	51.18	639.75
Amendment to Project-Based Section 8 Housing Assistance Payments Contract [Contract B] Pursuant to Section 8(bb)(1) of the United States Housing Act of 1937 (HUD–93185b)	25	25	0.50	13	39.72	496.50	51.18	639.75
Contract Renewal Request Form (HUD–9624)	2,000	2,000	1.00	2,000	39.72	79,440.00	51.18	102,360.00
OCAF Rent Adjustment Worksheet (HUD–9625)	7,957	7,957	1.00	7,957	39.72	316,052.04	51.18	407,239.26
Letters to Owners/Agents: Option 1 and 3 (HUD–9626)	419	419	0.25	105	39.72	4,160.67	51.18	5,361.11
Letters to Owners/Agents: Option 2 and 4 (HUD–9627)	1,801	1,801	0.25	450	39.72	17,883.93	51.18	23,043.80
Request to Renew Using Non–Section 8 Units in the Section 8 Project as a Market Rent Ceiling (HUD–9629)	10	10	0.50	5	39.72	198.60	51.18	255.90
Request to Renew Using FMRs as Market Ceiling (HUD–9630)	88	88	0.50	44	39.72	1,747.68	51.18	2,251.92
Sample Use Agreement (HUD–9634)	55	55	0.50	28	39.72	1,092.30	51.18	1,407.45
Projects Preparing a Budget-Based Rent Increase (HUD–9635)	1,697	1,697	1.00	1,697	39.72	67,404.84	51.18	86,852.46
Housing Assistance Payments Basic Renewal Contract—One-Year Term (HUD–9636)	500	500	0.50	250	39.72	9,930.00	51.18	12,795.00
Housing Assistance Payments Basic Renewal Contract—Multi-Year Term (HUD–9637)	800	800	0.50	400	39.72	15,888.00	51.18	20,472.00
Housing Assistance Payments Renewal Contract for Mark-Up-To-Market Project (HUD–9638)	169	169	0.50	85	39.72	3,356.34	51.18	4,324.71
Housing Assistance Payments Preservation Renewal Contract (HUD–9639)	213	213	0.50	107	39.72	4,230.18	51.18	5,450.67
Housing Assistance Payments Interim (Full) Mark-To-Market Renewal Contract (HUD–9640)	53	53	0.50	27	39.72	1,052.58	51.18	1,356.27
Housing Assistance Payments Interim (Lite) Mark-To-Market Renewal Contract (HUD–9641)	68	68	0.50	34	39.72	1,350.48	51.18	1,740.12
Housing Assistance Payments Full Mark-To-Market Renewal Contract (HUD–9642)	63	63	0.50	32	39.72	1,251.18	51.18	1,612.17
Housing Assistance Payments Watch List Renewal Contract (HUD–9643)	117	117	0.50	59	39.72	2,323.62	51.18	2,994.03
Project-Based Assistance Housing Assistance Payments Contract For Previous Mod Rehab Projects (HUD–9644)	25	25	0.50	13	39.72	496.50	51.18	639.75
Housing Assistance Payments Program Housing Finance & Development Agencies Extension Amendment to Old Regulation State Agency Housing Assistance Payments Contract (HUD–9647)	10	10	0.50	5	39.72	198.60	51.18	255.90
Consent to Assignment of HAP Contract as Security for Freddie Mac Financing (HUD–9648a)	50	50	0.50	25	39.72	993.00	51.18	1,279.50
Consent to Assignment of HAP Contract to FNMA as Security for FNMA Credit Enhancement (HUD–9648d)	50	50	0.50	25	39.72	993.00	51.18	1,279.50
Consent to Assignment of HAP Contract as Security for Financing (HUD–9649)	600	600	0.50	300	39.72	11,916.00	51.18	15,354.00
Consent to Assignment of Senior Preservation Rental Assistance Contract (SPRAC) as Security for Financing (HUD–9649a)	50	50	1.00	50	39.72	1,986.00	51.18	2,559.00
Consent to Assignment of HAP Contract as Security for FNMA Financing (HUD–9651)	100	100	0.50	50	39.72	1,986.00	51.18	2,559.00
Total	21,765	21,765	....	16,655	....	661,516.74	....	852,377.31

Description of the need for the information and proposed use: The *Section 8 Renewal Policy Guidebook* explains the various options available under the Multifamily Housing Reform and Affordability Act of 1997 (MAHRA) for the renewal of expiring project-based section 8 contracts and the adjustment of contract rents and establishes related administrative policies. Forms included in the information collection are used in the renewal and contract rent adjustment processes. For example, listed forms are used to establish market rents; amend rents; request renewal of a Section 8 contract under the Multifamily Housing Reform and Affordability Act of 1997; and ensure the acceptable operation of properties assisted under a Section 8 HAP contract.

This information collection includes a new form titled ''Assignment, Assumption, and Amendment of Assignment, Assumption, and Amendment of Section 8 Housing Assistance Payments (HAP) Contract'' (form HUD–5988) that is included as Attachment A to this Notice. In addition to soliciting public comments as described in this Section, HUD seeks input on use of the new form that will be required for the full assignment of a HAP contract. A draft of the new form is attached to this Notice for review. See below as follows.

Respondents: Businesses or other for-profit and not-for-profit entities.

Estimated Number of Respondents: 21,765.

Estimated Number of Responses: 21,765.

Frequency of Response: Various.

Average Hours per Response: 0.56 hours.

Total Estimated Burden Hours: 16,655 hours.

B. Solicitation of Public Comment

This notice is soliciting comments from members of the public and affected parties concerning the collection of information described in Section A on the following:

(1) 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) The accuracy of the agency's estimate of the burden 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 those who are to respond; including through the use of appropriate automated collection techniques or other forms of information technology, *e.g.,* permitting electronic submission of responses.

HUD encourages interested parties to submit comment.

C. Authority

Section 3507 of the Paperwork Reduction Act of 1995, 44 U.S.C. 3507.

Jeffrey D. Little,

General Deputy Assistant Secretary, Office of Housing.

BILLING CODE 4210–67–P

U.S. DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

OFFICE OF MULTIFAMILY HOUSING PROGRAMS

ASSIGNMENT, ASSUMPTION, AND AMENDMENT OF SECTION 8 HOUSING ASSISTANCE PAYMENTS (HAP) CONTRACT

SECTION 8 HAP CONTRACT NUMBER: ______________________

PROJECT NAME: ______________________

PROJECT LOCATION (City/Town, State): ______________________

ASSIGNOR/SELLER: ______________________

ASSIGNEE/BUYER: ______________________

CONTRACT ADMINISTRATOR: ______________________

This form is used in the administration of the project-based rental assistance program, as authorized under section 8 of the United States Housing Act of 1937, and is intended to assist the Department in ensuring that the operation of the project complies with program requirements. The public reporting burden for completing this form is estimated to average 30 minutes per response, including the time for reviewing instructions, searching existing data sources, and gathering and maintaining the data needed. The information collected is required to obtain benefits. HUD may disclose certain information to Federal, State, or local agencies when relevant to civil, criminal, or regulatory investigations and prosecutions. Information collected will not otherwise be disclosed or released outside of HUD, except as required and permitted by law. HUD may not collect this information, and you are not required to complete this form, unless it displays a currently valid OMB control number.

This Assignment, Assumption, and Amendment of Section 8 Housing Assistance Payments Contract ("Assignment") is made this ____ day of ________________, 20___ by and among the Contract Administrator, the Assignor/Seller, and the Assignee/Buyer, as each is identified on page 1, and shall be effective on the date set forth above ("Effective Date"). Only revisions to this form that are necessitated by State law, as determined solely by the United States Department of Housing and Urban Development ("HUD"), are permitted.

I. RECITALS

A. Previously, the Assignor/Seller or a former owner of the multifamily housing project identified on page 1 ("Project") entered into an original Section 8 housing assistance payments ("HAP") Contract ("Original HAP Contract") with the contract administrator at that time (HUD, or a public housing agency ("PHA") acting under an annual contributions contract ("ACC") with HUD). The Original HAP Contract was authorized under section 8 of the United States Housing Act of 1937 ("Act"), 42 U.S.C. § 1437f. If still in its original term (i.e., without having expired and been renewed, as described in the following paragraph), the Original HAP Contract is being assigned, assumed, and amended.

B. If the Original HAP Contract previously expired, it was renewed under a contract ("Renewal Contract") or under successive Renewal Contracts, as authorized under the Multifamily Assisted Housing Reform and Affordability Act of 1997, 42 U.S.C. § 1437f note, and the Renewal Contract currently in effect is being assigned, assumed, and amended.

C. A copy of the Original HAP Contract is attached and designated "Exhibit A."

D. If the Original HAP Contract previously expired and was renewed, a copy of the Renewal Contract currently in effect is also attached and is designated "Exhibit B."

E. The term "HAP Contract" means the Original HAP Contract (if no Renewal Contract) or the Renewal Contract currently in effect, as applicable. The term "Contract Administrator" means the current contract administrator (HUD, or a PHA, as applicable), as identified on page 1.

F. If this Assignment is in connection with a sale or lease of the Project, the Assignor/Seller and the Assignee/Buyer have entered into an agreement for such sale or lease, which includes the real property on which the Project is located, and any and all improvements situated thereon.

G. The Assignor/Seller wishes to assign, and the Assignee/Buyer wishes to assume, the HAP Contract, including all the rights and obligations thereunder.

H. The Assignor/Seller and/or the Assignee/Buyer have requested HUD's written consent to the assignment of the HAP Contract, and both understand that such consent is subject to the terms and conditions set forth in this Assignment.

I. The Assignor/Seller, the Assignee/Buyer, and the Contract Administrator therefore agree as follows:

II. ASSIGNMENT BY ASSIGNOR/SELLER

A. The Assignor/Seller hereby irrevocably assigns the HAP Contract, including all the rights and obligations thereunder, to the Assignee/Buyer.

B. The Assignor/Seller is hereby released from all future obligations arising under the HAP Contract, on or after the Effective Date, provided, however, that (i) the release shall not apply to any breach of the HAP Contract based on events, circumstances, or conditions occurring before the Effective Date; and (ii) the Assignor/Seller shall remain obligated to file any annual financial statements that the HAP Contract or any applicable law or regulation may require for the period preceding the Effective Date.

C. Nothing in this Assignment shall be construed to impair, limit, or otherwise affect any right that the Contract Administrator or HUD has or may have against the Assignor/Seller for any violation of the HAP Contract that occurred or may have occurred on or before the Effective Date.

III. ASSUMPTION BY THE ASSIGNEE/BUYER. The Assignee/Buyer hereby assumes the HAP Contract, including all the rights and obligations thereunder, as amended by this Assignment.

IV. AMENDMENT. The Assignee/Buyer (referred to in this Section IV as the "Owner") and the Contract Administrator hereby amend the HAP Contract to contain the following new provisions:

A. "Compliance with applicable Federal statutes and regulations, as amended from time to time. The Owner shall comply with all applicable Federal statutes and regulations, as amended from time to time, including all applicable regulations in 24 C.F.R. part 5, as amended from time to time, including without limitation the following:

1. 2 C.F.R. part 200 ("Uniform Administrative Requirements, Cost Principles, and Audit Requirements for Federal Awards");
2. 24 C.F.R. § 5.107 ("Audit Requirements for Non-Profit Organizations");
3. 24 C.F.R. part 5 subpart G ("Physical Condition Standards and Inspection Requirements");
4. 24 C.F.R. part 5 subpart H ("Uniform Financial Reporting Standards"); and
5. 24 C.F.R. part 200 subpart P ("Physical Condition of Multifamily Properties")."

B. "Annual financial reports. Notwithstanding anything to the contrary in the HAP Contract, including any previous amendment to the HAP Contract, the Owner shall comply with the following provisions:

1. Within ninety (90) days, or such period established in writing by HUD, following the end of each fiscal year, Owner shall prepare a financial report for the Owner's fiscal year, or the portion thereof that started with the Owner's assumption of the HAP Contract, based on an examination of the books and records of the Owner in accordance with generally accepted accounting principles and in such other form and substance as specified by HUD in supplemental guidance, and provide such report to

the Contract Administrator and HUD (if a PHA is the Contract Administrator) in such form, substance, and manner as may be specified by HUD under the Uniform Financial Reporting Standards at 24 C.F.R. § 5.801 ("UFRS"), or any successor regulations.

2. Unless specifically waived or modified by HUD or to the extent otherwise exempt, Owner shall: (a) engage an independent, licensed Certified Public Accountant ("CPA") to audit the Owner's annual financial report and to produce an audit report in accordance with both Generally Accepted Government Auditing Standards and Generally Accepted Auditing Standards; (b) engage an independent, licensed CPA to perform an agreed-upon procedure, in accordance with the American Institute of Certified Public Accountants Statement on Standards for Attestation Engagements, to compare the financial data template information submitted electronically by the Owner to HUD against the annual financial report examined by, and the audit report prepared by, the independent, licensed CPA, and report any variances to HUD; and (c) furnish to the Contract Administrator and HUD (if a PHA is the Contract Administrator) the audit report, and any other reports relating to the annual financial report or the audit report as required by HUD, by such means and in such form, substance, and manner as may be specified by HUD under UFRS, or any successor regulations.

3. To the extent certain non-profit Owners' requirement to submit annual financial reports may be waived or modified by HUD, or such Owners may otherwise be exempt from compliance, such waiver, modification, or exemption shall not be construed to relieve Owner of any requirements of this provision, except for those requirements specifically waived, modified, or exempt from.

4. If Owner fails to perform as required pursuant to this provision, the Contract Administrator or HUD (if a PHA is the Contract Administrator) may, at its sole election, and in a manner determined by HUD, and without affecting any other provisions herein, and without first providing notice of default of the HAP Contract to the Owner, initiate or cause to be initiated a forensic audit of the Owner's books, records, and accounts in such a manner as to provide to the Contract Administrator and HUD (if a PHA is the Contract Administrator) with as much of the same information that would have been provided had the Owner not failed to perform as required. Any such audit initiated by the Contract Administrator or HUD does not relieve Owner of the requirement to submit to the Contract Administrator and HUD (if a PHA is the Contract Administrator) an annual audited financial report as required pursuant to this provision."

C. "<u>Applicability and binding nature on successors and assigns.</u> The duties and obligations set forth in the HAP Contract, as amended by this Assignment, shall apply during the remainder of the term of the HAP Contract and during each successive renewal term and shall further apply to and be binding on each of the Assignee/Buyer's successors and assigns."

V. CONSENT BY HUD. Subject to the terms and conditions set forth herein and as evidenced by the signature of HUD's authorized representative on page 7, HUD hereby consents to the assignment of the HAP Contract.

VI. RIGHTS OF PARTIES, GOVERNING LAW, AND EXECUTION

A. Nothing in this Assignment shall be construed to impair, limit, or otherwise affect any rights that the Assignor/Seller, the Assignee/Buyer, the Contract Administrator, and/or HUD has or may have under the HAP Contract.

B. This Assignment shall be governed and construed in accordance with the laws of the State in which the Project is located and, to the extent that any provision is inconsistent with such laws, with the laws of the United States of America.

C. This Assignment may be executed in counterparts, each of which shall be considered an original for all purposes. Any and all counterparts shall together constitute one and the same instrument.

D. Unless signed by an authorized representative of the Contract Administrator and of HUD, this Assignment shall have no legal effect, and no housing assistance payments shall be made under the HAP Contract to the Assignee/Buyer.

Signature Page 1 of 2

ASSIGNOR/SELLER

I/We, the undersigned, certify under penalty of perjury that the information provided above is true and correct. WARNING: Anyone who knowingly submits a false claim or makes a false statement is subject to criminal and/or civil penalties, including confinement for up to 5 years, fines, and civil and administrative penalties. (18 U.S.C. §§ 287, 1001, 1010, 1012; 31 U.S.C. §§ 3729, 3802)

______________________ ____

(Print or Type)

By: ____

Signature of authorized representative

____

Name and official title of signatory (Print or Type)

ASSIGNEE/BUYER

I/We, the undersigned, certify under penalty of perjury that the information provided above is true and correct. WARNING: Anyone who knowingly submits a false claim or makes a false statement is subject to criminal and/or civil penalties, including confinement for up to 5 years, fines, and civil and administrative penalties. (18 U.S.C. §§ 287, 1001, 1010, 1012; 31 U.S.C. §§ 3729, 3802)

____

(Print or Type)

By: ____

Signature of authorized representative

____

Name and official title of signatory (Print or Type)

Signature Page 2 of 2

CONTRACT ADMINISTRATOR (HUD, or a PHA acting under an ACC with HUD)

____

(Print or Type)

By: ____

Signature of authorized representative

____

Name and official title of signatory (Print or Type)

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

By: ____

Signature of authorized representative

____

Name and official title of signatory (Print or Type)

EXHIBIT A
(ORIGINAL HAP CONTRACT)

EXHIBIT B
(RENEWAL CONTRACT CURRENTLY IN EFFECT)

[FR Doc. 2022–26452 Filed 12–5–22; 8:45 am]

BILLING CODE 4210–67–C

INTERNATIONAL TRADE COMMISSION

[Inv. No. 337–TA–1345]

Certain Automated Retractable Vehicle Steps and Components Thereof; Institution of Investigation

AGENCY: U.S. International Trade Commission.

ACTION: Notice.

SUMMARY: Notice is hereby given that a complaint was filed with the U.S. International Trade Commission on October 28, 2022, under section 337 of the Tariff Act of 1930, as amended, on behalf of Lund Motion Products, Inc. of Brea, California. Supplements to the complaint were filed on November 14, 2022. The complaint, as supplemented, alleges violations of section 337 based upon the importation into the United States, the sale for importation, and the sale within the United States after importation of certain automated retractable vehicle steps and components thereof by reason of the infringement of certain claims of U.S. Patent No. 9,272,667 (''the '667 patent); U.S. Patent No. 9,527,449 (''the '449 Patent''); U.S. Patent No. 9,511,717 (''the '717 Patent''); and U.S. Patent No. 11,198,395 (''the '395 patent''). The complaint further alleges that an industry in the United States exists as required by the applicable Federal Statute. The complainant requests that the Commission institute an investigation and, after the investigation, issue a general exclusion order, or in the alternative a limited exclusion order, and cease and desist orders.

ADDRESSES: The complaint, except for any confidential information contained therein, may be viewed on the Commission's electronic docket (EDIS) at *https://edis.usitc.gov.* For help accessing EDIS, please email *EDIS3Help@usitc.gov.* Hearing impaired individuals are advised that information on this matter can be obtained by contacting the Commission's TDD terminal on (202) 205–1810. Persons with mobility impairments who will need special assistance in gaining access to the Commission should contact the Office of the Secretary at (202) 205–2000. General information concerning the Commission may also be obtained by accessing its internet server at *https://www.usitc.gov.*

FOR FURTHER INFORMATION CONTACT: Pathenia M. Proctor, The Office of Unfair Import Investigations, telephone (202) 205–2560.

SUPPLEMENTARY INFORMATION:

Authority: The authority for institution of this investigation is contained in section 337 of the Tariff Act of 1930, as amended, 19 U.S.C. 1337, and in section 210.10 of the Commission's Rules of Practice and Procedure, 19 CFR 210.10 (2022).

Scope of Investigation: Having considered the complaint, the U.S. International Trade Commission, on November 30, 2022, ordered that—

(1) Pursuant to subsection (b) of section 337 of the Tariff Act of 1930, as amended, an investigation be instituted to determine whether there is a violation of subsection (a)(1)(B) of section 337 in the importation into the United States, the sale for importation,

or the sale within the United States after importation of certain products identified in paragraph (2) by reason of infringement of one or more of claims 1–3 and 5 of the '395 patent; claims 1–13 of the '667 patent; claims 1, 4–11, and 16 of the '717 patent; and claims 7–12 of the '449 patent; and whether an industry in the United States exists as required by subsection (a)(2) of section 337;

(2) Pursuant to section 210.10(b)(1) of the Commission's Rules of Practice and Procedure, 19 CFR 210.10(b)(1), the plain language description of the accused products or category of accused products, which defines the scope of the investigation, is ''automatic powered retractable vehicle steps and components thereof'';

(3) For the purpose of the investigation so instituted, the following are hereby named as parties upon which this notice of investigation shall be served:

(a) The complainant is:

Lund Motion Products, Inc., 3172 Nasa Street, Brea, CA 92821

(b) The respondents are the following entities alleged to be in violation of section 337, and are the parties upon which the complaint is to be served:

Anhui Aggeus Auto-Tech Co., Ltd. a/k/a Wuhu, Woden Auto Parts Co., Ltd. a/k/a Wuhu Wow-good, Auto-tech Co. Ltd. a/k/a Anhui Wollin International Co., Ltd., No. 9, Zhanghe Road, Yijiang District, Wuhu, Anhui, China, 241002

Rough Country LLC, 2450 Huish Rd., Dyersburg, TN 38024

Southern Truck LLC a/k/a Top Gun Customz, 11927 Sager Rd., Swanton, OH 43558

Meyer Distributing, Inc., 560 E 25th St., Jasper, IN 47546

Earl Owen Company, Inc., 1235 W Trinity Mills Rd., Carrollton, TX 75006

(c) The Office of Unfair Import Investigations, U.S. International Trade Commission, 500 E Street SW, Suite 401, Washington, DC 20436; and

(4) For the investigation so instituted, the Chief Administrative Law Judge, U.S. International Trade Commission, shall designate the presiding Administrative Law Judge.

Responses to the complaint and the notice of investigation must be submitted by the named respondents in accordance with section 210.13 of the Commission's Rules of Practice and Procedure, 19 CFR 210.13. Pursuant to 19 CFR 201.16(e) and 210.13(a), as amended in 85 FR 15798 (March 19, 2020), such responses will be considered by the Commission if received not later than 20 days after the date of service by the complainant of the complaint and the notice of investigation. Extensions of time for submitting responses to the complaint and the notice of investigation will not be granted unless good cause therefor is shown.

Failure of a respondent to file a timely response to each allegation in the complaint and in this notice may be deemed to constitute a waiver of the right to appear and contest the allegations of the complaint and this notice, and to authorize the administrative law judge and the Commission, without further notice to the respondent, to find the facts to be as alleged in the complaint and this notice and to enter an initial determination and a final determination containing such findings, and may result in the issuance of an exclusion order or a cease and desist order or both directed against the respondent.

By order of the Commission.

Issued: December 1, 2022.

Katherine Hiner,

Acting Secretary to the Commission.

[FR Doc. 2022–26500 Filed 12–5–22; 8:45 am]

BILLING CODE 7020–02–P

DEPARTMENT OF JUSTICE

[OMB Number 1125–0013]

Agency Information Collection Activities; Proposed eCollection; eComments Requested; Revision of a Currently Approved Collection; Request by Organization for Accreditation or Renewal of Accreditation of Non-Attorney Representative (Form EOIR–31A)

AGENCY: Executive Office for Immigration Review, Department of Justice.

ACTION: 30-Day notice.

SUMMARY: The Executive Office for Immigration Review (EOIR), Department of Justice (DOJ), will be submitting the following information collection request to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act of 1995. This proposed information collection was previously published in the **Federal Register** on November 3, 2022, allowing for a 30-day comment period, however the email address for comments was incorrect. This notice corrects the email address and extends the period for comment.

DATES: Comments are encouraged and will be accepted for an additional 30 days until January 5, 2023.

FOR FURTHER INFORMATION CONTACT: If you have additional comments especially on the estimated public burden or associated response time, suggestions, or need a copy of the proposed information collection instrument with instructions or additional information, please contact Lauren Alder Reid, Assistant Director, Office of Policy, Executive Office for Immigration Review, 5107 Leesburg Pike, Suite 2500, Falls Church, VA 22041, telephone: (703) 305–0289. Written comments and/or suggestions can also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attention Department of Justice Desk Officer, Washington, DC 20503 or sent to *OIRA_submission@omb.eop.gov*.

SUPPLEMENTARY INFORMATION: Written comments and suggestions from the public and affected agencies concerning the proposed collection of information are encouraged. Your comments should address one or more of the following four points:

- 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;
- 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;
- Enhance the quality, utility, and clarity of the information to be collected; and/or
- 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:* Revision of a currently approved collection.

2. *The Title of the Form/Collection:* Request by Organization for Accreditation or Renewal Accreditation of Non-Attorney Representative.

3. *The agency form number, if any, and the applicable component of the Department sponsoring the collection:*

Form number: EOIR–31A.

Sponsor: Office of Legal Access Programs, Executive Office for Immigration Review, U.S. Department of Justice.

4. *Affected public who will be asked or required to respond, as well as a brief*

abstract: Non-profit organizations seeking accreditation or renewal of accreditation of its representatives by the Office of Legal Access Programs of the Executive Office for Immigration Review.

Abstract: This information collection will allow an organization to seek accreditation or renewal of accreditation of a non-attorney representative to appear before EOIR and/or the Department of Homeland Security. This information collection is necessary to determine whether a representative meets the eligibility requirements for accreditation. Requests can be made using a fillable pdf. application or electronic submission.

5. *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:* It is estimated that 550 respondents will complete the form annually for initial accreditation requests, with an average of 3 hours per response, for a total of 1,650 hours. It is estimated that 369 respondents will complete the form annually for renewal requests, with an average of 7 hours per response, for a total of 2,583 hours.

6. *An estimate of the total public burden (in hours) associated with the collection:* There are an estimated 4,233 total annual burden hours associated with this collection.

If additional information is required contact: Robert Houser, Department Clearance Officer, Policy and Planning Staff, Office of the Chief Information Officer, Justice Management Division, United States Department of Justice, Two Constitution Square, 145 N Street NE, Suite 3E.206, Washington, DC 20530.

Dated: November 30, 2022.

Robert Houser,

Department Clearance Officer Policy and Planning Staff, Office of the Chief Information Officer, U.S. Department of Justice.

[FR Doc. 2022–26437 Filed 12–5–22; 8:45 am]

BILLING CODE 4410–30–P

DEPARTMENT OF JUSTICE

Notice of Lodging of Proposed Consent Decree Under the Resource Conservation and Recovery Act and Clean Air Act

On November 30, 2022, the Department of Justice lodged a proposed consent decree with the United States District Court for the Eastern District of Wisconsin in the lawsuit entitled *United States and State of Wisconsin* v. *Container Life Cycle Management, LLC,* Civil Action No. 22–cv–01423 (E.D. Wis.).

The consent decree addresses Resource Conservation and Recovery Act (RCRA) and Clean Air Act (CAA) violations at defendant Container Life Cycle Management LLC's (CLCM's) container reconditioning facilities in the Milwaukee, Wisconsin, area. CLCM will pay a $1.6 million civil penalty to be split evenly between the United States and the State.

The United States alleged violations of RCRA related to storage and handling of hazardous waste at the company's facilities in St. Francis and Oak Creek, Wisconsin and its then-operating facility in Milwaukee, Wisconsin. The complaint also alleges CAA violations, for, among other things, CLCM's failure to control emissions of volatile organic compounds as required by the EPA-approved Wisconsin state implementation plan.

To address alleged RCRA violations, the consent decree requires CLCM to implement a container management plan, or CMP, for a two-year period. The CMP provides for storage of heavy and non-empty containers in RCRA-compliant hazardous waste storage areas. Certain reporting requirements continue beyond the initial two-year period.

To address CAA violations, CLCM must continuously operate a previously installed regenerative thermal oxidizer, in order to control air emissions of volatile organic compounds at the St. Francis facility. It will also construct additional emissions capture systems within the St. Francis facility. At the Oak Creek facility, CLCM must install and continuously operate a new digital data recorder to record the temperature of the drum reclamation furnace afterburner, and maintain an afterburner temperature at or above 1,650 degrees. Finally, CLCM will be required to conduct performance testing at both the St. Francis and Oak Creek facilities.

The publication of this notice opens a period for public comment on the consent decree. Comments should be addressed to the Assistant Attorney General, Environment and Natural Resources Division, and should refer to *United States and State of Wisconsin* v. *Container Life Cycle Management, LLC,* D.J. Ref. No. 90–7–1–11802/1. All comments must be submitted no later than thirty (30) days after the publication date of this notice. Comments may be submitted either by email or by mail:

To submit comments:	*Send them to:*
By email	*pubcomment-ees.enrd@usdoj.gov.*
By mail	Assistant Attorney General, U.S. DOJ—ENRD, P.O. Box 7611, Washington, DC 20044–7611.

During the public comment period, the Consent Decree may be examined and downloaded at this Justice Department website: *https://www.justice.gov/enrd/consent-decrees.* We will provide a paper copy of the Consent Decree, including all exhibits, upon written request and payment of reproduction costs. Please mail your request and payment to: Consent Decree Library, U.S. DOJ—ENRD, P.O. Box 7611, Washington, DC 20044–7611.

Please enclose a check or money order for $39.75 (25 cents per page reproduction cost) payable to the United States Treasury. For a paper copy without the exhibits and signature pages, the cost is $15.50.

Patricia McKenna,

Assistant Section Chief, Environmental Enforcement Section, Environment and Natural Resources Division.

[FR Doc. 2022–26502 Filed 12–5–22; 8:45 am]

BILLING CODE 4410–15–P

NATIONAL SCIENCE FOUNDATION

Notice; Cancellation of Meeting

AGENCY: National Science Foundation.

ACTION: Notice; cancellation of meeting date.

SUMMARY: The National Science Foundation published a notice in the **Federal Register** concerning a meeting of the National Artificial Intelligence Research Resource Task Force. The meeting scheduled for Wednesday, December 7, 2022, at 1 p.m. (ET) is cancelled. The notice is in the **Federal Register** of Tuesday, November 1, 2022, in FR Doc. 2022–23733, in the third column of page 65829.

FOR FURTHER INFORMATION CONTACT: Please contact Crystal Robinson *crrobins@nsf.gov* or 703–292–8687.

Dated: November 30, 2022.

Crystal Robinson,

Committee Management Officer, National Science Foundation.

[FR Doc. 2022–26423 Filed 12–5–22; 8:45 am]

BILLING CODE 7555–01–P

NATIONAL SCIENCE FOUNDATION

Agency Information Collection Activities: Comment Request; Analysis of Partnerships

AGENCY: National Science Foundation.

ACTION: Notice.

SUMMARY: The National Science Foundation (NSF) is announcing plans to establish this collection. In accordance with the requirements of the Paperwork Reduction Act of 1995, we are providing opportunity for public comment on this action. After obtaining and considering public comment, NSF will prepare the submission requesting Office of Management and Budget (OMB) clearance of this collection for no longer than 3 years.

DATES: Written comments on this notice must be received by February 6, 2023 to be assured consideration. Comments received after that date will be considered to the extent practical. Send comments to address below.

FOR FURTHER INFORMATION CONTACT: Suzanne H. Plimpton, Reports Clearance Officer, National Science Foundation, 2415 Eisenhower Avenue, Suite W18200, Alexandria, Virginia 22314; telephone (703) 292–7556; or send email to *splimpto@nsf.gov.* Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339, which is accessible 24 hours a day, 7 days a week, 365 days a year (including Federal holidays).

SUPPLEMENTARY INFORMATION:

Title of Collection: Information collection for evaluating NSF partnership activities.

OMB Number: 3145–NEW.

Expiration Date of Approval: Not applicable.

Type of Request: Intent to seek approval to establish an information collection.

Abstract: Building partnerships is a high priority for NSF, as evidenced by two consecutive Agency Priority Goals (APGs for FY 2018 and FY 2020) focused on developing a partnerships strategy. The importance of partnerships is also echoed in the recent National Science Board's Vision 2030 report and reflected in the new Directorate for Technology, Innovation and Partnerships (TIP). Partnerships are hypothesized to accelerate discovery in several ways: they can enable access to expertise, resources, and infrastructure; accelerate the flow of knowledge and expertise; and expand communities of researchers. NSF direct partnerships are established by NSF with other federal agencies, industry, private foundations, non-governmental organizations, and foreign science agencies.

NSF is requesting OMB approval for the NSF to collect information from past and present participants and partners in NSF partnership programs. The information collection will enable the Evaluation and Assessment Capability (EAC) Section within NSF to garner quantitative and qualitative information that will be used to inform programmatic improvements related to partnership models at NSF including partnerships between NSF and other entities and funding opportunities that require or encourage partnerships between grantees. This information collection, which entails collecting information from relevant NSF grantees and partners, is in accordance with the Agency's commitment to improving service delivery as well as the Agency's strategic goal to ''advance the capability of the Nation to meet current and future challenges.''

Use of the Information: The data collected will be used for NSF internal and external reports related to partnerships, program level studies, and evaluations. These outputs will inform decisions NSF makes regarding future activities.

Respondents: Participants in NSF grants (principal investigators, partners, research personnel, etc.). Partners involved in NSF partnership programs.

Estimated Number of Respondents: 300.

Estimate Burden on the Public: Estimated at 450 hours for a one-time collection.

Comments: Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information shall have practical utility; (b) the accuracy of the Agency's estimate of the burden of the proposed collection of information; (c) ways to enhance the quality, utility, and clarity of the information on respondents, including through the use of automated collection techniques or other forms of information technology; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

Please submit one copy of your comments by only one method. All submissions received must include the agency name and collection name identified above for this information collection. Commenters are strongly encouraged to transmit their comments electronically via email. Comments, including any personal information provided become a matter of public record. They will be summarized and/or included in the request for Office of Management and Budget approval of the information collection request.

Dated: December 1, 2022.

Suzanne H. Plimpton,

Reports Clearance Officer, National Science Foundation.

[FR Doc. 2022–26465 Filed 12–5–22; 8:45 am]

BILLING CODE 7555–01–P

NATIONAL SCIENCE FOUNDATION

Agency Information Collection Activities: Comment Request

AGENCY: National Center for Science and Engineering Statistics, National Science Foundation.

ACTION: Notice.

SUMMARY: The National Center for Science and Engineering Statistics (NCSES) within the National Science Foundation (NSF) is announcing plans to request renewal of the Survey of Doctorate Recipients (SDR), [OMB Control Number 3145–0020]. In accordance with the requirements of the Paperwork Reduction Act of 1995, NCSES is providing opportunity for public comment on this action. After obtaining and considering public comment, NCSES will prepare the submission requesting that OMB approve clearance of this collection for three years.

DATES: Written comments on this notice must be received by February 6, 2023 to be assured of consideration. Comments received after that date will be considered to the extent practicable. Send comments to the address below.

FOR FURTHER INFORMATION CONTACT: Suzanne H. Plimpton, Reports Clearance Officer, National Science Foundation, 2415 Eisenhower Avenue, Suite E7465, Alexandria, Virginia 22314; telephone (703) 292–7556; or send email to *splimpto@nsf.gov.* Individuals who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339, which is accessible 24 hours a day, 7 days a week, 365 days a year (including Federal holidays).

SUPPLEMENTARY INFORMATION:

Title of Collection: 2023 Survey of Doctorate Recipients.

OMB Control Number: 3145–0020.

Expiration Date of Current Approval: July 31, 2024.

Type of Request: Intent to seek approval to extend an information collection for three years.

Abstract: Established within the NSF by the America COMPETES

Reauthorization Act of 2010 § 505, codified in the National Science Foundation Act of 1950, as amended, the National Center for Science and Engineering Statistics (NCSES) serves as a central Federal clearinghouse for the collection, interpretation, analysis, and dissemination of objective data on science, engineering, technology, and research and development for use by practitioners, researchers, policymakers, and the public.

NCSES is the primary sponsor of the Survey of Doctorate Recipients (SDR); the National Institutes of Health (NIH) serves as a co-sponsor. The SDR has been conducted biennially since 1973 and is a longitudinal survey. The 2023 SDR will consist of a sample of individuals under 76 years of age who have earned a research doctoral degree in a science, engineering, or health (SEH) field from a U.S. academic institution. The purpose of this panel survey is to collect data to provide national estimates on the doctoral science and engineering workforce and changes in their employment, education, and demographic characteristics. NCSES uses these data to prepare essential congressionally mandated reports (explained below). Government agencies and academic researchers use SDR data and publications to make planning decisions regarding science and engineering research, training, and employment opportunities. Employers also use the SDR to understand trends in employment sectors, industry types, and salary. Students who want to learn about the relationship between graduate education and careers often obtain valuable information from the SDR. Data and publications from the SDR are available to the public on the NCSES website: *https://www.nsf.gov/statistics/srvydoctoratework/.* The first SDR longitudinal data products were released in 2022.

The SDR will collect data by web survey, mail questionnaire, and computer-assisted telephone interviews beginning in June 2023. The survey will be collected in conformance with the Confidential Information Protection and Statistical Efficiency Act (CIPSEA) of 2018 and the individual's response to the survey is voluntary. NCSES will ensure that all information collected will be kept strictly confidential and will be used only for statistical purposes.

Use of the Information: NCSES uses the information from the SDR to prepare two congressionally mandated reports: *Diversity and STEM: Women, Minorities, and Persons with Disabilities* and *Science and Engineering Indicators.* NCSES publishes statistics from the SDR in many reports, primarily in the biennial series, *Characteristics of Scientists and Engineers with U.S. Doctorates.* As with prior SDR data collections, a cross-sectional public release file of collected data designed to protect respondent confidentiality will be made available to researchers on the NCSES website: *https://ncsesdata.nsf.gov/datadownload/.*

Expected Respondents: The U.S. Office of Management and Budget (OMB) previously directed that NCSES enhance and expand the sample to measure employment outcomes by the fine field of degree taxonomy used in the Survey of Earned Doctorates (SED). NCSES initiated this change in the 2015 cycle and has since maintained it by developing a detailed field of degree taxonomy based on the SED fine fields that is aggregated to a level that is reportable and sustainable. (For information defining these fields, see the survey technical notes.) The SDR sample is drawn using the SED as a frame. The SDR uses a fixed panel design with a sample of new doctoral graduates added to the panel in each biennial survey cycle. The sample stratification, allocation, and estimation precision targets are described in the survey description.

For the 2023 SDR, a statistical sample of approximately 130,000 individuals with U.S. earned doctorates in science, engineering, or health will be contacted. The sample consists of all eligible cases from the previous cycle (115,000) after removing cases that have never responded (6,700), including those from the 2017 SDR new sample and the 2019 SDR supplemental sample, as well as a sample of 10,000 new doctoral graduates. In addition, the sample includes 5,000 cases that will be part of a non-production bridge panel designed to quantify the potential impact of question wording modifications on key survey estimates. For 2023, the new graduate sample received their U.S. doctorate between July 2019 and June 2021. Across the full sample, NCSES estimates approximately 88% of individuals will reside in the U.S. and the remaining 12% will reside abroad.

Estimate of Burden: NCSES expects the overall 2023 SDR response rate to be approximately 70 percent. The amount of time to complete the questionnaire may vary depending on an individual's circumstances; however, based on 2021 SDR completion times and the potential addition of new retirement-related items for a subsample of respondents, NCSES estimates an average completion time of approximately 25 minutes. NCSES estimates that the average annual burden for the 2023 survey cycle over the course of the three-year OMB clearance period will be no more than 12,639 hours [(130,000 individuals × 70% response × 25 minutes)/60 minutes/3 years].

Comments: Comments are invited on (a) whether the proposed collection of information is necessary for the proper performance of the functions of NCSES, including whether the information shall have practical utility; (b) the accuracy of NCSES's estimate of the burden of the proposed collection of information; (c) ways to enhance the quality, use, and clarity of the information on respondents, including through the use of automated collection techniques or other forms of information technology; and (d) ways to 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.

Dated: November 30, 2022.

Suzanne H. Plimpton,

Reports Clearance Officer, National Science Foundation.

[FR Doc. 2022–26422 Filed 12–5–22; 8:45 am]

BILLING CODE 7555–01–P

NUCLEAR REGULATORY COMMISSION

[NRC–2022–0199]

Applications and Amendments to Facility Operating Licenses and Combined Licenses Involving Proposed No Significant Hazards Considerations and Containing Sensitive Unclassified Non-Safeguards Information and Order Imposing Procedures for Access to Sensitive Unclassified Non-Safeguards Information

AGENCY: Nuclear Regulatory Commission.

ACTION: License amendment request; notice of opportunity to comment, request a hearing, and petition for leave to intervene; order imposing procedures.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) received and is considering approval of three amendment requests. The amendment requests are for Joseph M. Farley Nuclear Plant, Units 1 and 2; Byron Station, Unit 2; and Beaver Valley Power Station, Units 1 and 2. For each amendment request, the NRC proposes to determine that they involve no significant hazards consideration

(NSHC). Because each amendment request contains sensitive unclassified non-safeguards information (SUNSI), an order imposes procedures to obtain access to SUNSI for contention preparation by persons who file a hearing request or petition for leave to intervene.

DATES: Comments must be filed by January 5, 2023. A request for a hearing or petitions for leave to intervene must be filed by February 6, 2023. Any potential party as defined in section 2.4 of title 10 of the *Code of Federal Regulations* (10 CFR) who believes access to SUNSI is necessary to respond to this notice must request document access by December 16, 2022.

ADDRESSES: You may submit comments by any of the following methods; however, the NRC encourages electronic comment submission through the Federal rulemaking website:

- *Federal Rulemaking Website:* Go to *https://www.regulations.gov* and search for Docket ID NRC–2022–0199. Address questions about Docket IDs in *Regulations.gov* 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.
- *Mail comments to:* Office of Administration, Mail Stop: TWFN–7–A60M, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, ATTN: Program Management, Announcements and Editing Staff.

For additional direction on obtaining information and submitting comments, see ''Obtaining Information and Submitting Comments'' in the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: Kathleen Entz, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, telephone: 301–415–2464, email: *Kathleen.Entz@nrc.gov.*

SUPPLEMENTARY INFORMATION:

I. Obtaining Information and Submitting Comments

A. Obtaining Information

Please refer to Docket ID NRC–2022–0199, facility name, unit number(s), docket number(s), application date, and subject when contacting the NRC about the availability of information for this action. You may obtain publicly available information related to this action by any of the following methods:

- *Federal Rulemaking Website:* Go to *https://www.regulations.gov* and search for Docket ID NRC–2022–0199.
- *NRC's Agencywide Documents Access and Management System (ADAMS):* You may obtain publicly available documents online in the ADAMS Public Documents collection at *https://www.nrc.gov/reading-rm/adams.html.* To begin the search, select ''Begin Web-based ADAMS Search.'' For problems with ADAMS, please contact the NRC's Public Document Room (PDR) reference staff at 800–397–4209, 301–415–4737, or by email to *PDR.Resource@nrc.gov.* The ADAMS accession number for each document referenced (if it is available in ADAMS) is provided the first time that it is mentioned in this document.
- *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 800–397–4209 or 301–415–4737, between 8:00 a.m. and 4:00 p.m. Eastern Time (ET), Monday through Friday, except Federal holidays.

B. Submitting Comments

The NRC encourages electronic comment submission through the Federal rulemaking website (*https://www.regulations.gov*). Please include Docket ID NRC–2022–0199, facility name, unit number(s), docket number(s), application date, and subject, in your comment submission.

The NRC cautions you not to include identifying or contact information that you do not want to be publicly disclosed in your comment submission. The NRC will post all comment submissions at *https://www.regulations.gov* as well as enter the comment submissions into ADAMS. The NRC does not routinely edit comment submissions to remove identifying or contact information.

If you are requesting or aggregating comments from other persons for submission to the NRC, then you should inform those persons not to include identifying or contact information that they do not want to be publicly disclosed in their comment submission. Your request should state that the NRC does not routinely edit comment submissions to remove such information before making the comment submissions available to the public or entering the comment into ADAMS.

II. Background

Pursuant to Section 189a.(2) of the Atomic Energy Act of 1954, as amended (the Act), the NRC is publishing this notice. The Act requires the Commission to publish notice of any amendments issued, or proposed to be issued and grants the Commission the authority to issue and make immediately effective any amendment to an operating license or combined license, as applicable, upon a determination by the Commission that such amendment involves NSHC, notwithstanding the pendency before the Commission of a request for a hearing from any person.

This notice includes notices of amendments containing SUNSI.

III. Notice of Consideration of Issuance of Amendments to Facility Operating Licenses and Combined Licenses, Proposed No Significant Hazards Consideration Determination, and Opportunity for a Hearing

The Commission has made a proposed determination that the following amendment requests involve NSHC. Under the Commission's regulations in 10 CFR 50.92, this means that operation of the facility in accordance with the proposed amendment would not (1) involve a significant increase in the probability or consequences of an accident previously evaluated, or (2) create the possibility of a new or different kind of accident from any accident previously evaluated, or (3) involve a significant reduction in a margin of safety. The basis for this proposed determination for each amendment request is shown in this notice.

The Commission is seeking public comments on these proposed determinations. Any comments received within 30 days after the date of publication of this notice will be considered in making any final determination.

Normally, the Commission will not issue the amendments until the expiration of 60 days after the date of publication of this notice. The Commission may issue any of these license amendments before expiration of the 60-day period provided that its final determination is that the amendment involves no significant hazards consideration. In addition, the Commission may issue any of these amendments prior to the expiration of the 30-day comment period if circumstances change during the 30-day comment period such that failure to act in a timely way would result, for example, in derating or shutdown of the facility. If the Commission takes action prior to the expiration of either the comment period or the notice period, it will publish a notice of issuance in the **Federal Register**. If the Commission makes a final no significant hazards consideration determination for any of these amendments, any hearing will take place after issuance. The Commission expects that the need to take this action will occur very infrequently.

A. Opportunity To Request a Hearing and Petition for Leave To Intervene

Within 60 days after the date of publication of this notice, any persons (petitioner) whose interest may be affected by any of these actions may file a request for a hearing and petition for leave to intervene (petition) with respect to that action. Petitions shall be filed in accordance with the Commission's ''Agency Rules of Practice and Procedure'' in 10 CFR part 2. Interested persons should consult a current copy of 10 CFR 2.309. The NRC's regulations are accessible electronically from the NRC Library on the NRC's website at *https://www.nrc.gov/reading-rm/doc-collections/cfr.* If a petition is filed, the Commission or a presiding officer will rule on the petition and, if appropriate, a notice of a hearing will be issued.

As required by 10 CFR 2.309(d) the petition should specifically explain the reasons why intervention should be permitted with particular reference to the following general requirements for standing: (1) the name, address, and telephone number of the petitioner; (2) the nature of the petitioner's right to be made a party to the proceeding; (3) the nature and extent of the petitioner's property, financial, or other interest in the proceeding; and (4) the possible effect of any decision or order which may be entered in the proceeding on the petitioner's interest.

In accordance with 10 CFR 2.309(f), the petition must also set forth the specific contentions that the petitioner seeks to have litigated in the proceeding. Each contention must consist of a specific statement of the issue of law or fact to be raised or controverted. In addition, the petitioner must provide a brief explanation of the bases for the contention and a concise statement of the alleged facts or expert opinion that support the contention and on which the petitioner intends to rely in proving the contention at the hearing. The petitioner must also provide references to the specific sources and documents on which the petitioner intends to rely to support its position on the issue. The petition must include sufficient information to show that a genuine dispute exists with the applicant or licensee on a material issue of law or fact. Contentions must be limited to matters within the scope of the proceeding. The contention must be one that, if proven, would entitle the petitioner to relief. A petitioner who fails to satisfy the requirements at 10 CFR 2.309(f) with respect to at least one contention will not be permitted to participate as a party.

Those permitted to intervene become parties to the proceeding, subject to any limitations in the order granting leave to intervene. Parties have the opportunity to participate fully in the conduct of the hearing with respect to resolution of that party's admitted contentions, including the opportunity to present evidence, consistent with the NRC's regulations, policies, and procedures.

Petitions must be filed no later than 60 days from the date of publication of this notice. Petitions and motions for leave to file new or amended contentions that are filed after the deadline will not be entertained absent a determination by the presiding officer that the filing demonstrates good cause by satisfying the three factors in 10 CFR 2.309(c)(1)(i) through (iii). The petition must be filed in accordance with the filing instructions in the ''Electronic Submissions (E-Filing)'' section of this document.

If a hearing is requested, and the Commission has not made a final determination on the issue of NSHC, the Commission will make a final determination on the issue of NSHC. The final determination will serve to establish when the hearing is held. If the final determination is that the amendment request involves NSHC, the Commission may issue the amendment and make it immediately effective, notwithstanding the request for a hearing. Any hearing would take place after issuance of the amendment. If the final determination is that the amendment request involves a significant hazards consideration, then any hearing held would take place before the issuance of the amendment unless the Commission finds an imminent danger to the health or safety of the public, in which case it will issue an appropriate order or rule under 10 CFR part 2.

A State, local governmental body, Federally recognized Indian Tribe, or agency thereof, may submit a petition to the Commission to participate as a party under 10 CFR 2.309(h)(1). The petition should state the nature and extent of the petitioner's interest in the proceeding. The petition should be submitted to the Commission no later than 60 days from the date of publication of this notice. The petition must be filed in accordance with the filing instructions in the ''Electronic Submissions (E-Filing)'' section of this document, and should meet the requirements for petitions set forth in this section, except that under 10 CFR 2.309(h)(2) a State, local governmental body, or Federally recognized Indian Tribe, or agency thereof does not need to address the standing requirements in 10 CFR 2.309(d) if the facility is located within its boundaries. Alternatively, a State, local governmental body, Federally recognized Indian Tribe, or agency thereof may participate as a non-party under 10 CFR 2.315(c).

If a petition is submitted, any person who is not a party to the proceeding and is not affiliated with or represented by a party may, at the discretion of the presiding officer, be permitted to make a limited appearance pursuant to the provisions of 10 CFR 2.315(a). A person making a limited appearance may make an oral or written statement of his or her position on the issues but may not otherwise participate in the proceeding. A limited appearance may be made at any session of the hearing or at any prehearing conference, subject to the limits and conditions as may be imposed by the presiding officer. Details regarding the opportunity to make a limited appearance will be provided by the presiding officer if such sessions are scheduled.

B. Electronic Submissions (E-Filing)

All documents filed in NRC adjudicatory proceedings including documents filed by an interested State, local governmental body, Federally recognized Indian Tribe, or designated agency thereof that requests to participate under 10 CFR 2.315(c), must be filed in accordance with 10 CFR 2.302. The E-Filing process requires participants to submit and serve all adjudicatory documents over the internet, or in some cases, to mail copies on electronic storage media, unless an exemption permitting an alternative filing method, as further discussed, is granted. Detailed guidance on electronic submissions is located in the ''Guidance for Electronic Submissions to the NRC'' (ADAMS Accession No. ML13031A056) and on the NRC's public website at *https://www.nrc.gov/site-help/e-submittals.html.*

To comply with the procedural requirements of E-Filing, at least 10 days prior to the filing deadline, the participant should contact the Office of the Secretary by email at *Hearing.Docket@nrc.gov,* or by telephone at 301–415–1677, to (1) request a digital identification (ID) certificate, which allows the participant (or its counsel or representative) to digitally sign submissions and access the E-Filing system for any proceeding in which it is participating; and (2) advise the Secretary that the participant will be submitting a petition or other adjudicatory document (even in instances in which the participant, or its counsel or representative, already holds an NRC-issued digital ID certificate). Based upon this information, the Secretary will establish an electronic docket for the proceeding if the Secretary has not already established an electronic docket.

Information about applying for a digital ID certificate is available on the NRC's public website at *https://www.nrc.gov/site-help/e-submittals/getting-started.html.* After a digital ID certificate is obtained and a docket created, the participant must submit adjudicatory documents in Portable Document Format. Guidance on submissions is available on the NRC's public website at *https://www.nrc.gov/site-help/electronic-sub-ref-mat.html.* A filing is considered complete at the time the document is submitted through the NRC's E-Filing system. To be timely, an electronic filing must be submitted to the E-Filing system no later than 11:59 p.m. ET on the due date. Upon receipt of a transmission, the E-Filing system time stamps the document and sends the submitter an email confirming receipt of the document. The E-Filing system also distributes an email that provides access to the document to the NRC's Office of the General Counsel and any others who have advised the Office of the Secretary that they wish to participate in the proceeding, so that the filer need not serve the document on those participants separately. Therefore, applicants and other participants (or their counsel or representative) must apply for and receive a digital ID certificate before adjudicatory documents are filed to obtain access to the documents via the E-Filing system.

A person filing electronically using the NRC's adjudicatory E-Filing system may seek assistance by contacting the NRC's Electronic Filing Help Desk through the ''Contact Us'' link located on the NRC's public website at *https://www.nrc.gov/site-help/e-submittals.html,* by email to *MSHD.Resource@nrc.gov,* or by a toll-free call at 866–672–7640. The NRC Electronic Filing Help Desk is available between 9:00 a.m. and 6:00 p.m., ET, Monday through Friday, except Federal holidays.

Participants who believe that they have good cause for not submitting documents electronically must file an exemption request, in accordance with 10 CFR 2.302(g), with their initial paper filing stating why there is good cause for not filing electronically and requesting authorization to continue to submit documents in paper format. Such filings must be submitted in accordance with 10 CFR 2.302(b)–(d). Participants filing adjudicatory documents in this manner are responsible for serving their documents on all other participants. Participants granted an exemption under 10 CFR 2.302(g)(2) must still meet the electronic formatting requirement in 10 CFR 2.302(g)(1), unless the participant also seeks and is granted an exemption from 10 CFR 2.302(g)(1).

Documents submitted in adjudicatory proceedings will appear in the NRC's electronic hearing docket, which is publicly available at *https://adams.nrc.gov/ehd,* unless excluded pursuant to an order of the presiding officer. If you do not have an NRC-issued digital ID certificate as previously described, click ''cancel'' when the link requests certificates and you will be automatically directed to the NRC's electronic hearing dockets, where you will be able to access any publicly available documents in a particular hearing docket. Participants are requested not to include personal privacy information such as social security numbers, home addresses, or personal phone numbers in their filings unless an NRC regulation or other law requires submission of such information. With respect to copyrighted works, except for limited excerpts that serve the purpose of the adjudicatory filings and would constitute a Fair Use application, participants should not include copyrighted materials in their submission.

Constellation Energy Generation, LLC; Byron Station, Unit 2; Will County, IL

Docket No(s)	50–455.
Application Date	August 31, 2022.
ADAMS Accession No	ML22243A094.
Location in Application of NSHC	Attachment 1, Pages 13–16.
Brief Description of Amendment(s)	The amendment proposes to revise language in Byron Station technical specification (TS) 2.1.1, ''Reactor Core SLs [Safety Limits],'' and TS 4.2.1, ''Fuel Assemblies,'' to allow a previously irradiated accident tolerant fuel lead test assembly to be further irradiated during Byron Station, Unit 2, Cycle 25, starting in the fall 2023.
Proposed Determination	NSHC.
Name of Attorney for Licensee, Mailing Address	Jason Zorn, Associate General Counsel, Constellation Energy Generation, 101 Constitution Ave NW, Washington, DC 20001.
NRC Project Manager, Telephone Number	Joel Wiebe, 301–415–6606.

Energy Harbor Nuclear Corp. and Energy Harbor Nuclear Generation LLC; Beaver Valley Power Station, Units 1 and 2; Beaver County, PA

Docket No(s)	50–334, 50–412.
Application Date	August 31, 2022.
ADAMS Accession No	ML22249A257.
Location in Application of NSHC	Attachment 1, Pages 6–8.
Brief Description of Amendment(s)	The proposed amendment requests to revise TS 5.6.3, ''Core Operating Limits Report (COLR),'' to add Westinghouse Electric Company LLC Topical Report WCAP–16996–P–A, Rev, 1. ''Realistic LOCA [Loss of Coolant Accident] Evaluation Methodology Applied to the Full Spectrum of Break Sizes (FULL SPECTRUM LOCA Methodology),'' to the list of approved analytical methods used to determine core operating limits and adds a note to restrict future use of legacy methods. The proposed amendment would also revise TS 4.2.1, ''Fuel Assemblies,'' by removing Zircalloy from the list of fuel rod cladding.
Proposed Determination	NSHC.
Name of Attorney for Licensee, Mailing Address	Rick Giannantonio, General Counsel, Energy Harbor Nuclear Corp., 168 E Market Street, Akron, OH 44308–2014.
NRC Project Manager, Telephone Number	Brent Ballard, 301–415–0680.

Southern Nuclear Operating Company, Inc.; Joseph M. Farley Nuclear Plant, Units 1 and 2; Houston County, AL	
Docket No(s)	50–348, 50–364.
Application Date	September 21, 2022.
ADAMS Accession No	ML22264A300.
Location in Application of NSHC	Pages E–5 through E–7 of the Enclosure.
Brief Description of Amendment(s)	The licensee proposes an amendment to the Joseph M. Farley Nuclear Plant, Units 1 and 2, TS to revise TS 4.3, ''Fuel Storage,'' to correct tabulated values in the associated spent fuel pool criticality analysis.
Proposed Determination	NSHC.
Name of Attorney for Licensee, Mailing Address	Millicent Ronnlund, Vice President and General Counsel, Southern Nuclear Operating Co., Inc., P.O. Box 1295, Birmingham, AL 35201–1295.
NRC Project Manager, Telephone Number	John Lamb, 301–415–3100.

Order Imposing Procedures for Access to Sensitive Unclassified Non-Safeguards Information for Contention Preparation

Constellation Energy Generation, LLC; Byron Station, Unit 2; Will County, IL Energy Harbor Nuclear Corp. and Energy Harbor Nuclear Generation LLC; Beaver Valley Power Station, Units 1 and 2; Beaver County, PA

Southern Nuclear Operating Company, Inc.; Joseph M. Farley Nuclear Plant, Units 1 and 2; Houston County, AL

A. This Order contains instructions regarding how potential parties to this proceeding may request access to documents containing Sensitive Unclassified Non-Safeguards Information (SUNSI).

B. Within 10 days after publication of this notice of hearing or opportunity for hearing, any potential party who believes access to SUNSI is necessary to respond to this notice may request access to SUNSI. A ''potential party'' is any person who intends to participate as a party by demonstrating standing and filing an admissible contention under 10 CFR 2.309. Requests for access to SUNSI submitted later than 10 days after publication of this notice will not be considered absent a showing of good cause for the late filing, addressing why the request could not have been filed earlier.

C. The requestor shall submit a letter requesting permission to access SUNSI to the Office of the Secretary, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, Attention: Rulemakings and Adjudications Staff, and provide a copy to the Deputy General Counsel for Licensing, Hearings, and Enforcement, Office of the General Counsel, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001. The expedited delivery or courier mail address for both offices is: U.S. Nuclear Regulatory Commission, 11555 Rockville Pike, Rockville, Maryland 20852. The email addresses for the Office of the Secretary and the Office of the General Counsel are *Hearing.Docket@nrc.gov* and *RidsOgcMailCenter.Resource@nrc.gov*, respectively.[1] The request must include the following information:

(1) A description of the licensing action with a citation to this **Federal Register** notice;

(2) The name and address of the potential party and a description of the potential party's particularized interest that could be harmed by the action identified in C.(1); and

(3) The identity of the individual or entity requesting access to SUNSI and the requestor's basis for the need for the information in order to meaningfully participate in this adjudicatory proceeding. In particular, the request must explain why publicly available versions of the information requested would not be sufficient to provide the basis and specificity for a proffered contention.

D. Based on an evaluation of the information submitted under paragraph C, the NRC staff will determine within 10 days of receipt of the request whether:

(1) There is a reasonable basis to believe the petitioner is likely to establish standing to participate in this NRC proceeding; and

(2) The requestor has established a legitimate need for access to SUNSI.

E. If the NRC staff determines that the requestor satisfies both D.(1) and D.(2), the NRC staff will notify the requestor in writing that access to SUNSI has been granted. The written notification will contain instructions on how the requestor may obtain copies of the requested documents, and any other conditions that may apply to access to those documents. These conditions may include, but are not limited to, the signing of a Non-Disclosure Agreement or Affidavit, or Protective Order[2] setting forth terms and conditions to prevent the unauthorized or inadvertent disclosure of SUNSI by each individual who will be granted access to SUNSI.

F. Filing of Contentions. Any contentions in these proceedings that are based upon the information received as a result of the request made for SUNSI must be filed by the requestor no later than 25 days after receipt of (or access to) that information. However, if more than 25 days remain between the petitioner's receipt of (or access to) the information and the deadline for filing all other contentions (as established in the notice of hearing or opportunity for hearing), the petitioner may file its SUNSI contentions by that later deadline.

G. Review of Denials of Access.

(1) If the request for access to SUNSI is denied by the NRC staff after a determination on standing and requisite need, the NRC staff shall immediately notify the requestor in writing, briefly stating the reason or reasons for the denial.

(2) The requestor may challenge the NRC staff's adverse determination by filing a challenge within 5 days of receipt of that determination with: (a) the presiding officer designated in this proceeding; (b) if no presiding officer has been appointed, the Chief Administrative Judge, or if this individual is unavailable, another administrative judge, or an Administrative Law Judge with jurisdiction pursuant to 10 CFR 2.318(a); or (c) if another officer has been designated to rule on information access issues, with that officer.

(3) Further appeals of decisions under this paragraph must be made pursuant to 10 CFR 2.311.

H. Review of Grants of Access. A party other than the requestor may challenge an NRC staff determination granting access to SUNSI whose release would harm that party's interest

[1] While a request for hearing or petition to intervene in this proceeding must comply with the filing requirements of the NRC's ''E-Filing Rule,'' the initial request to access SUNSI under these procedures should be submitted as described in this paragraph.

[2] Any motion for Protective Order or draft Non-Disclosure Affidavit or Agreement for SUNSI must be filed with the presiding officer or the Chief Administrative Judge if the presiding officer has not yet been designated, within 30 days of the deadline for the receipt of the written access request.

independent of the proceeding. Such a challenge must be filed within 5 days of the notification by the NRC staff of its grant of access and must be filed with: (a) the presiding officer designated in this proceeding; (b) if no presiding officer has been appointed, the Chief Administrative Judge, or if this individual is unavailable, another administrative judge, or an Administrative Law Judge with jurisdiction pursuant to 10 CFR 2.318(a); or (c) if another officer has been designated to rule on information access issues, with that officer.

If challenges to the NRC staff determinations are filed, these procedures give way to the normal process for litigating disputes concerning access to information. The availability of interlocutory review by the Commission of orders ruling on such NRC staff determinations (whether granting or denying access) is governed by 10 CFR 2.311.[3]

I. The Commission expects that the NRC staff and presiding officers (and any other reviewing officers) will consider and resolve requests for access to SUNSI, and motions for protective orders, in a timely fashion in order to minimize any unnecessary delays in identifying those petitioners who have standing and who have propounded contentions meeting the specificity and basis requirements in 10 CFR part 2. The attachment to this Order summarizes the general target schedule for processing and resolving requests under these procedures.

It is so ordered.

Dated: November 22, 2022.

For the Nuclear Regulatory Commission.

Brooke P. Clark,

Secretary of the Commission.

ATTACHMENT 1—GENERAL TARGET SCHEDULE FOR PROCESSING AND RESOLVING REQUESTS FOR ACCESS TO SENSITIVE UNCLASSIFIED NON-SAFEGUARDS INFORMATION IN THIS PROCEEDING

Day	Event/activity
0	Publication of **Federal Register** notice of hearing or opportunity for hearing, including order with instructions for access requests.
10	Deadline for submitting requests for access to Sensitive Unclassified Non-Safeguards Information (SUNSI) with information: supporting the standing of a potential party identified by name and address; describing the need for the information in order for the potential party to participate meaningfully in an adjudicatory proceeding.
60	Deadline for submitting petition for intervention containing: (i) demonstration of standing; and (ii) all contentions whose formulation does not require access to SUNSI (+25 Answers to petition for intervention; +7 petitioner/requestor reply).
20	U.S. Nuclear Regulatory Commission (NRC) staff informs the requestor of the staff's determination whether the request for access provides a reasonable basis to believe standing can be established and shows need for SUNSI. (NRC staff also informs any party to the proceeding whose interest independent of the proceeding would be harmed by the release of the information.) If NRC staff makes the finding of need for SUNSI and likelihood of standing, NRC staff begins document processing (preparation of redactions or review of redacted documents).
25	If NRC staff finds no "need" or no likelihood of standing, the deadline for petitioner/requestor to file a motion seeking a ruling to reverse the NRC staff's denial of access; NRC staff files copy of access determination with the presiding officer (or Chief Administrative Judge or other designated officer, as appropriate). If NRC staff finds "need" for SUNSI, the deadline for any party to the proceeding whose interest independent of the proceeding would be harmed by the release of the information to file a motion seeking a ruling to reverse the NRC staff's grant of access.
30	Deadline for NRC staff reply to motions to reverse NRC staff determination(s).
40	(Receipt +30) If NRC staff finds standing and need for SUNSI, deadline for NRC staff to complete information processing and file motion for Protective Order and draft Non-Disclosure Agreement or Affidavit. Deadline for applicant/licensee to file Non-Disclosure Agreement or Affidavit for SUNSI.
A	If access granted: issuance of presiding officer or other designated officer decision on motion for protective order for access to sensitive information (including schedule for providing access and submission of contentions) or decision reversing a final adverse determination by the NRC staff.
A + 3	Deadline for filing executed Non-Disclosure Agreements or Affidavits. Access provided to SUNSI consistent with decision issuing the protective order.
A + 28	Deadline for submission of contentions whose development depends upon access to SUNSI. However, if more than 25 days remain between the petitioner's receipt of (or access to) the information and the deadline for filing all other contentions (as established in the notice of hearing or notice of opportunity for hearing), the petitioner may file its SUNSI contentions by that later deadline.
A + 53	(Contention receipt +25) Answers to contentions whose development depends upon access to SUNSI.
A + 60	(Answer receipt +7) Petitioner/Intervenor reply to answers.
>A + 60	Decision on contention admission.

[FR Doc. 2022–25851 Filed 12–5–22; 8:45 am]

BILLING CODE 7590–01–P

POSTAL REGULATORY COMMISSION

[Docket Nos. MC2023–67 and CP2023–67; MC2023–68 and CP2023–68]

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:* December 8, 2022.

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.

[3] Requestors should note that the filing requirements of the NRC's E-Filing Rule (72 FR 49139; August 28, 2007, as amended at 77 FR 46562; August 3, 2012, 78 FR 34247, June 7, 2013) apply to appeals of NRC staff determinations (because they must be served on a presiding officer or the Commission, as applicable), but not to the initial SUNSI request submitted to the NRC staff under these procedures.

FOR FURTHER INFORMATION CONTACT: David A. Trissell, General Counsel, at 202–789–6820.

SUPPLEMENTARY INFORMATION:

Table of Contents

I. Introduction

The Commission gives notice that the Postal Service filed request(s) for the Commission to consider matters related to negotiated service agreement(s). The request(s) may propose the addition or removal of a negotiated service agreement from the Market Dominant or the Competitive product list, or the modification of an existing product currently appearing on the Market Dominant or the Competitive product list.

Section II identifies the docket number(s) associated with each Postal Service request, the title of each Postal Service request, the request's acceptance date, and the authority cited by the Postal Service for each request. For each request, the Commission appoints an officer of the Commission to represent the interests of the general public in the proceeding, pursuant to 39 U.S.C. 505 (Public Representative). Section II also establishes comment deadline(s) pertaining to each request.

The public portions of the Postal Service's request(s) can be accessed via the Commission's website (*http://www.prc.gov*). Non-public portions of the Postal Service's request(s), if any, can be accessed through compliance with the requirements of 39 CFR 3011.301.[1]

The Commission invites comments on whether the Postal Service's request(s) in the captioned docket(s) are consistent with the policies of title 39. For request(s) that the Postal Service states concern Market Dominant product(s), applicable statutory and regulatory requirements include 39 U.S.C. 3622, 39 U.S.C. 3642, 39 CFR part 3030, and 39 CFR part 3040, subpart B. For request(s) that the Postal Service states concern Competitive product(s), applicable statutory and regulatory requirements include 39 U.S.C. 3632, 39 U.S.C. 3633, 39 U.S.C. 3642, 39 CFR part 3035, and 39 CFR part 3040, subpart B. Comment deadline(s) for each request appear in section II.

II. Docketed Proceeding(s)

1. *Docket No(s).:* MC2023–67 and CP2023–67; *Filing Title:* USPS Request to Add Priority Mail Express International, Priority Mail International & First-Class Package International Service Contract 12 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date:* November 30, 2022; *Filing Authority:* 39 U.S.C. 3642, 39 CFR 3040.130 through 3040.135, and 39 CFR 3035.105; *Public Representative:* Jethro Dely; *Comments Due:* December 8, 2022.

2. *Docket No(s).:* MC2023–68 and CP2023–68; *Filing Title:* USPS Request to Add Priority Mail Express, Priority Mail, First-Class Package Service & Parcel Select Contract 94 to Competitive Product List and Notice of Filing Materials Under Seal; *Filing Acceptance Date:* November 30, 2022; *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:* December 8, 2022.

This Notice will be published in the **Federal Register**.

Erica A. Barker,

Secretary.

[FR Doc. 2022–26496 Filed 12–5–22; 8:45 am]

BILLING CODE 7710–FW–P

[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).

POSTAL REGULATORY COMMISSION

[Docket No. PI2023–1; Order No. 6347]

Service Standards for Market Dominant Mail Products

AGENCY: Postal Regulatory Commission.

ACTION: Notice.

SUMMARY: The Commission is recognizing a recent filing by the Postal Service of its intent to establish new service standards for USPS Connect Local Mail and proposing corresponding revisions to its Service Performance Measurement (SPM) Plan for Market Dominant products. This notice informs the public of the filing, invites public comment, and takes other administrative steps.

DATES: *Comments are due:* December 14, 2022.

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: On November 23, 2022, the Postal Service filed a notice, pursuant to 39 CFR 3055.5, notifying the Commission of the Postal Service's intent to establish new service standards for USPS Connect Local Mail and proposing corresponding revisions to its Service Performance Measurement (SPM) Plan for Market Dominant products.[1] The Postal Service also, pursuant to 39 U.S.C. 3691(b)(2), requests approval to apply its existing internal service performance measurement system to USPS Connect Local Mail. Notice at 1. The most recent version of the SPM Plan that is the subject of this proceeding was approved for implementation on July 18, 2022, in Docket No. PI2022–3.[2] Accompanying the Notice is a library reference, which contains a copy of the Postal Service's SPM Plan, revised November 23, 2022 (both redline and clean versions).[3]

On November 10, 2021, the Postal Service announced its intention to conduct a market test of an experimental product denominated as USPS Connect Local Mail.[4] USPS Connect Local Mail is intended for local delivery, enabling customers to deposit USPS Connect Local Mail items at participating Destination Delivery Units (DDUs) or present them to mail carriers along their lines of travel to participating DDUs. Notice at 2. The Commission authorized the proposed market test on January 4, 2022.[5] The Postal Service now seeks to classify USPS Connect Local Mail as a new, permanent classification in the Mail Classification Schedule (MCS).[6] The Postal Service states that assuming its proposed classification changes are adopted in accordance with the expected date of implementation of January 22, 2023, the Postal Service plans to add USPS Connect Local Mail

[1] United States Postal Service Notice Concerning the Establishment of Service Standards and Measurement for USPS Connect™ Local and Request for Use of Internal Measurement System, November 23, 2022, at 1 (Notice).

[2] Docket No. PI2022–3, Order Directing the Postal Service to Request an Advisory Opinion Prior to Implementing its Proposed Change to the Critical Entry Times for Periodicals and Approving the Other Proposed Revisions to Market Dominant Service Performance Measurement Plan, July 18, 2022 (Order No. 6232).

[3] Library Reference USPS–LR–PI2023–1/1, November 23, 2022.

[4] Docket No. MT2022–1, United States Postal Service Notice of Market Test of Experimental Product—USPS Connect Local Mail, November 10, 2021.

[5] Docket No. MT2022–1, Order Authorizing Market Test of Experimental Product—USPS Connect Local Mail, January 4, 2022 (Order No. 6080).

[6] Notice at 3; *see* Docket No. MC2023–12, United States Postal Service Revised Request to Convert USPS Connect Local Mail to a Permanent Offering, November 9, 2022.

as price category within First-Class Mail Flats. Notice at 2.

Related to the Postal Service's request to add USPS Connect Local Mail as a new, permanent classification, the Postal Service plans to establish new service standards for USPS Connect Mail Local. Notice at 2. The Postal Service plans for USPS Connect Local Mail items accepted at a participating DDU by 0700 to receive a same-day service standard, and for mailpieces received at a participating DDU or by carrier pickup after 0700 to receive a 1-day service standard. *Id.* at 3. The Postal Service states its intention to revise 39 CFR 121.1 to establish a 0-day service standard for USPS Connect Local Mail and to include USPS Connect Local Mail in the 1-day service standard.[7]

The Postal Service also proposes, pursuant to 39 CFR 3055.5, to modify the existing SPM Plan to add USPS Connect Local Mail, describe the approach that will be followed to measure its service performance, and identify when such performance measurements will be reported. *Id.* at 4.

Finally, the Postal Service requests, pursuant to 39 U.S.C. 3691(b)(2), that the Commission approve the Postal Service's use of internal SPM to measure service performance for USPS Connect Local Mail. *Id.* The Postal Service specifically proposes using its existing internal Intelligent Mail package barcode (IMpb) system, which employs automated equipment to sort and track mailpieces. *Id.* at 4–5. The Postal Service proposes using IMpb tracking barcode scans at acceptance and delivery to measure service performance for USPS Connect Local Mail. *Id.* at 5.

Interested persons are invited to comment on the Postal Service's planned new service standards for USPS Connect Local Mail, proposed revisions to its SPM Plan, and request to use internal service performance measurement for USPS Connect Local Mail. Comments are due December 14, 2022. The Commission does not anticipate the need for reply comments at this time. The Commission intends to evaluate the comments received and use those suggestions to help carry out its service performance measurement responsibilities under Title 39 of the United States Code. Material filed in this docket will be available for review on the Commission's website, *http://www.prc.gov.* The Commission appoints Christopher C. Mohr to represent the interests of the general public (Public Representative) in this docket.

It is ordered:

1. Docket No. PI2023–1 is established for the purpose of considering the Postal Service's planned new service standards for USPS Connect Local mail, proposed revisions to its Service Performance Measurement Plan for Market Dominant products, and request to use internal service performance measurement for USPS Connect Local Mail.

2. Interested persons may submit written comments on any or all aspects of the Postal Service's proposals no later than December 14, 2022.

3. Christopher C. Mohr is designated to represent the interests of the general public in this docket.

4. The Secretary shall arrange for publication of this notice in the **Federal Register**.

By the Commission.

Erica A. Barker,

Secretary.

[FR Doc. 2022–26429 Filed 12–5–22; 8:45 am]

BILLING CODE 7710–FW–P

[7] *Id.* at 3–4. This proposed change was published in the **Federal Register**. *See* 87 FR 73468–69 (Nov. 30, 2022).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–96415; File No. SR–FINRA–2022–031]

Self-Regulatory Organizations; Financial Industry Regulatory Authority, Inc.; Notice of Filing of a Proposed Rule Change To Adopt FINRA Rules 6151 (Disclosure of Order Routing Information for NMS Securities) and 6470 (Disclosure of Order Routing Information for OTC Equity Securities)

November 30, 2022.

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 November 16, 2022, the Financial Industry Regulatory Authority, Inc. (''FINRA'') 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 FINRA. 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

FINRA is proposing to adopt FINRA Rules 6151 (Disclosure of Order Routing Information for NMS Securities) and 6470 (Disclosure of Order Routing Information for OTC Equity Securities) to require members to (i) publish order routing reports for orders in OTC Equity Securities, and (ii) submit their order routing reports for both OTC Equity Securities and NMS Securities to FINRA for publication on the FINRA website.

The text of the proposed rule change is available on FINRA's website at *http://www.finra.org,* at the principal office of FINRA and at the Commission's Public Reference Room.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, FINRA 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 these statements may be examined at the places specified in Item IV below. FINRA has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

Rule 606(a) of Regulation NMS[3] (''SEC Rule 606(a)'') requires broker-dealers to publicly disclose specified information about their order routing practices for NMS Securities,[4] including for non-directed orders in NMS stocks that are submitted on a ''held'' basis.[5] The SEC has stated that, as a result of these disclosures, ''customers—and retail investors in particular—that submit orders to their broker-dealers should be better able to assess the quality of order handling services

[3] 17 CFR 242.606(a).

[4] Generally, ''NMS Securities'' include listed stocks and options, and NMS stocks means any NMS Security other than an option. *See* 17 CFR 242.600(b).

[5] *See* Securities Exchange Act Release No. 84528 (November 2, 2018), 83 FR 58338 (November 19, 2018) (Disclosure of Order Handling Information; Final Rule) (''2018 Amendments Release''). The SEC did not specifically define ''held'' or ''not held'' orders, but stated that typically a ''not held'' order provides the broker-dealer with price and time discretion in handling the order, whereas a broker-dealer must attempt to execute a ''held'' order immediately. *See id.* at 58340 n.19. As noted by the SEC in the 2018 Amendments Release, broker-dealers utilize the ''held'' and ''not held'' order classifications as a matter of industry practice and to comply with regulatory requirements, including audit trail reporting requirements and the definition of ''covered order'' in Rule 600(b) of Regulation NMS. *See id.* at 58344.

provided by their broker-dealers and whether their broker-dealers are effectively managing potential conflicts of interest.'' [6]

FINRA believes these same goals would be furthered by providing investors with similar order handling information for unlisted stocks, which are not covered by the existing SEC Rule 606(a) disclosure requirements.[7] Accordingly, FINRA is proposing to adopt new Rule 6470 to require members to publish quarterly order routing disclosures primarily for non-directed held orders in OTC Equity Securities,[8] generally aligned with the SEC Rule 606(a) disclosures for NMS stocks but with modifications to account for differences between the market for NMS Securities and over-the-counter (''OTC'') markets, as described below. In addition, to make both the existing SEC Rule 606(a) disclosures and the new OTC Equity Security disclosures more accessible to investors, FINRA is proposing new Rule 6151 and paragraph (d) of new Rule 6470 to require members to send both disclosures to FINRA for centralized publication on the FINRA website, as described further below.

Disclosure of Order Routing Information for OTC Equity Securities

Proposed new Rule 6470, entitled ''Disclosure of Order Routing Information for OTC Equity Securities,'' would require the publication of order routing disclosures for OTC Equity Securities. Specifically, as is already required for broker-dealers with respect to held orders in NMS stocks under SEC Rule 606(a)(1), proposed Rule 6470(a) would require, among other things, every member to make publicly available for each calendar quarter a report on its routing of non-directed orders in OTC Equity Securities that are submitted on a held basis during that quarter, broken down by calendar month, and keep such report posted on an internet website that is free and readily accessible to the public for a period of three years from the initial date of posting on the internet website.[9] Also in line with the required publication timeframe for NMS stock disclosures under SEC Rule 606(a)(2), proposed Rule 6470(c) would require that a member make the new OTC Equity Security report publicly available within one month after the end of the quarter addressed in the report.[10]

Under Rule 606(a)(1), the SEC Rule 606(a) reports for NMS Securities are required to be broken out into separate sections for NMS stocks in the S&P 500 Index as of the first day of the quarter, other NMS stocks, and NMS Securities that are options. Since these categories are not relevant to the OTC market, FINRA is proposing to instead require that the new quarterly reports for OTC Equity Securities under Rule 6470(a) be separated into three sections to better reflect the OTC market. Specifically, the new reports would be required to be separated into three sections for: (i) domestic OTC Equity Securities; (ii) American Depository Receipts (''ADRs'') and foreign ordinaries that are OTC Equity Securities; and (iii) Canadian-listed securities trading in the United States as OTC Equity Securities. To provide for consistency across member reports, FINRA will publish a list of the OTC Equity Security symbols that fall under each category, and members would be required to publish reports in a manner consistent with such list.[11]

Under Rule 606(a)(1), the SEC Rule 606(a) reports for NMS Securities must be made available using the most recent versions of the XML schema and associated PDF renderer as published on the SEC's website. Similarly, Rule 6470(a) would specify that the new OTC Equity Security reports must be made available using the most recent versions of the XML schema and associated PDF renderer as published on the FINRA website. FINRA believes this requirement would ensure that reports are generated and published in standardized machine-readable and human-readable forms, which would benefit investors by permitting the public to more easily analyze and compare the OTC Equity Security reports across members, as well as to more easily perform combined analysis of both SEC Rule 606(a) and OTC Equity Security reports.[12]

With respect to the content of the new reports, Rule 6470(a) would require that each section of the new OTC Equity Security reports include the information specified in paragraphs (a)(1) through (4) of proposed Rule 6470, specifically: [13]

- the percentage of total orders [14] for the section that were not held orders and held orders, and the percentage of held orders for the section that were non-directed orders; [15]

[6] *See* 2018 Amendments Release, 83 FR 58338, 58423.

[7] FINRA notes that the SEC's Equity Market Structure Advisory Committee (''EMSAC'') previously recommended enhancing the current order routing disclosures required under SEC Rule 606 with information about OTC Equity Securities, and also expressed support for centralization of the reports. *See* EMSAC, Recommendations Regarding Modifying Rule 605 and Rule 606 (November 29, 2016), *https://www.sec.gov/spotlight/emsac/emsac-recommendations-rules-605-606.pdf.*

[8] An ''OTC Equity Security'' means any equity security that is not an NMS stock, other than a Restricted Equity Security. *See* FINRA Rule 6420(f). A ''Restricted Equity Security'' means any equity security that meets the definition of ''restricted security'' as contained in Securities Act Rule 144(a)(3). *See* FINRA Rule 6420(k).

[9] Proposed Rule 6470 would apply to ''every member,'' but FINRA notes that the focus of the proposed disclosures is held orders from customers in OTC Equity Securities, and some members may not engage in any activities involving held orders from customers in OTC Equity Securities. If a member does not accept any orders in OTC Equity Securities from customers during a given calendar quarter (whether held or not held), such member would not be required to publish a report under Rule 6470 for that quarter. Similarly, a member that accepted only not held orders in OTC Equity Securities from customers—but no held orders in OTC Equity Securities from customers—during a given calendar quarter would not be required to publish a report for that quarter. *See infra* note 21. Further, if a member accepted orders in OTC Equity Securities (whether held, not held, or both) only from other broker-dealers, but not from customers, during a given calendar quarter, such member would not be required to publish a report for that quarter.

[10] FINRA understands that some introducing firms route all of their orders in OTC Equity Securities to one or more clearing firms for further routing to other venues for execution. The SEC has provided guidance that, where an introducing firm routes all of its covered orders to one or more clearing firms for further routing and execution and the clearing firm in fact makes the routing decision, the introducing firm generally may comply with the order routing disclosure requirements by: (i) disclosing its relationship with the clearing firm(s) on its website that includes any payment for order flow received by the introducing firm, and (ii) adopting the clearing firm's disclosures by reference, provided that the introducing firm has examined the report and does not have reason to believe it materially misrepresents the order routing practices. FINRA intends to provide parallel guidance with respect to proposed Rule 6470. *See* SEC Division of Trading and Markets, Responses to Frequently Asked Questions Concerning Rule 606 of Regulation NMS, Question 12.01; *see also* SEC Division of Market Regulation, Staff Legal Bulletin No. 13A, Frequently Asked Questions About Rule 11Ac1–6, Question 4.

[11] If the Commission approves the proposed rule change, FINRA will provide information in the *Regulatory Notice* announcing the effective date regarding where members may access the list of OTC Equity Security symbols that FINRA will maintain on its website.

[12] FINRA would publish the technical specifications for the XML schema and associated PDF renderer on its website for member use in generating the new reports. FINRA expects that, subject to the differences between the SEC Rule 606(a) reports and the OTC Equity Security reports discussed above, the XML schema and associated PDF renderer published by FINRA would be substantially similar to those published by the SEC for the SEC Rule 606(a) reports.

[13] A template of the proposed new OTC Equity Security report that would be required under proposed Rule 6470 is attached as Exhibit 3 [sic].

[14] For purposes of proposed Rule 6470(a), ''total orders'' would include all orders from customers for the section, including both directed and non-directed orders from customers.

[15] For purposes of the proposed disclosures, a ''non-directed order'' would mean any order from a customer other than a directed order. Consistent with the definition of ''directed order'' under Regulation NMS, a ''directed order'' would mean an order from a customer that the customer specifically

Continued

• the identity of the ten venues to which the largest number of total non-directed held orders for the section were routed for execution [16] and of any venue to which five percent or more of non-directed held orders for the section were routed for execution, and the percentage of total non-directed held orders for the section routed to the venue; [17]

• for each identified venue, the net aggregate amount of any payment for order flow received, payment from any profit-sharing relationship received, transaction fees paid, and transaction rebates received, both as a total dollar amount and per order, for all non-directed held orders for the section; and

• a discussion of the material aspects of the member's relationship with each identified venue, including, without limitation, a description of any arrangement for payment for order flow and any profit-sharing relationship and a description of any terms of such arrangements, written or oral, that may influence a member's order routing decision including, among other things: incentives for equaling or exceeding an agreed upon order flow volume threshold, such as additional payments or a higher rate of payment; disincentives for failing to meet an agreed upon minimum order flow threshold, such as lower payments or the requirement to pay a fee; volume-based tiered payment schedules; and agreements regarding the minimum amount of order flow that the member would send to a venue.[18]

The proposed content of the new OTC Equity Security reports under proposed FINRA Rule 6470(a) generally parallels the content required to be included in SEC Rule 606(a) reports for NMS stocks pursuant to SEC Rule 606(a)(1)(i) through (iv), with the following differences to take into account the different market structure and characteristics of OTC Equity Securities. First, Rule 6470(a)(1) would require members to disclose the percentage of total orders for the section that were not held orders and held orders, in addition to disclosing the percentage of held orders for the section that were non-directed orders.[19] While SEC Rule 606(a) similarly requires broker-dealers to disclose the percentage of orders for each section that were non-directed orders, it does not require broker-dealers to disclose the percentage of total orders for each section that were not held orders and held orders.[20] FINRA believes that requiring members to provide information about the relative amount of a member's held and not held orders in the new reports proposed to be published under Rule 6470(a)(1) would provide investors, regulators, academics, and others seeking to review the reports with additional information regarding the business of brokers active in the OTC market.[21]

Second, the information required to be disclosed under SEC Rule 606(a)(i) through (iii) is required to be broken out into sections for market orders, marketable limit orders, non-marketable limit orders, and other orders. However, FINRA is not adopting these categories for OTC Equity Securities due to the absence of a centralized, self-regulatory organization (SRO)-disseminated national best bid and offer in the OTC market on which to standardize and base marketability. Finally, SEC Rule 606(a)(1)(iii) requires the disclosure of quantitative payment information both as a total dollar amount and per share. In light of different pricing practices in the OTC market, Rule 6470(a)(3) would instead require the quantitative disclosures for OTC Equity Securities to be expressed as both a total dollar amount and per order (rather than per share).[22]

Centralized Hosting of Order Routing Disclosures

As discussed above, SEC Rule 606(a) requires broker-dealers to publish their SEC Rule 606(a) reports for NMS

instructed the member to route to a particular venue for execution. *See* 17 CFR 242.600(b); *see also* 2018 Amendments Release, 83 FR 58338, 58339 n.4. FINRA notes that, similar to the definition of ''customer'' under Rule 600(b)(23) of Regulation NMS, a ''customer'' is defined under FINRA rules to exclude a broker or dealer. *See* FINRA Rule 0160(b)(4). Orders from other broker-dealers would therefore be excluded from the proposed disclosures.

[16] Consistent with the SEC's approach to SEC Rule 606(a), FINRA intends that, for purposes of the proposed disclosures for OTC Equity Securities, a ''venue'' would be defined broadly to cover any market center or any other person or entity to which a member routes orders for execution. *See, e.g.,* Securities Exchange Act Release No. 43590 (November 17, 2000), 65 FR 75414, 75427 n.63 (December 1, 2000) (Disclosure of Order Execution and Routing Practices) (''The term 'venue' is intended to be interpreted broadly to cover 'market centers' within the meaning of Rule 11Ac1–5(a)(14) [now Rule 600(b)(46) of Regulation NMS], as well as any other person or entity to which a broker routes non-directed orders for execution. Consequently, the term excludes an entity that is used merely as a vehicle to route an order to a venue selected by the broker-dealer.''); *see also* 17 CFR 242.600(b)(46) (''Market center means any exchange market maker, OTC market maker, alternative trading system, national securities exchange, or national securities association.''). Accordingly, for purposes of proposed Rule 6470, where an alternative trading system (''ATS'') offers both automatic order execution and order delivery functionality, the ATS should be identified as the venue only when the ATS provides order execution. FINRA believes identification of the ATS in these circumstances is appropriate because the ATS is the venue where the order was routed ''for execution,'' consistent with SEC guidance for the predecessor to SEC Rule 606. *See* SEC Division of Market Regulation, Staff Legal Bulletin No. 13A, Frequently Asked Questions About Rule 11Ac1–6, Question 12. Conversely, for purposes of proposed Rule 6470, in cases where the ATS instead provides order delivery, the separate market center to which the orders are delivered—*e.g.,* a market maker or other ATS—should be identified as the venue where the order was routed for execution.

[17] However, the proposed rule change would include a *de minimis* venue exception parallel to exemptive relief that the SEC has provided with respect to the SEC Rule 606(a) reports. *See* Letter from Annette L. Nazareth, Director, SEC Division of Market Regulation, to Neal E. Sullivan & Gail Marshall-Smith, Bingham Dana LLP (on behalf of First Union Securities, Inc.), dated June 22, 2001, 2001 SEC No-Act. LEXIS 903; *see also* SEC Division of Market Regulation, Staff Legal Bulletin No. 13A, Frequently Asked Questions About Rule 11Ac1–6, Question 2. Specifically, proposed Rule 6470(b) would provide an exception from the requirement for a member to identify venues that received less than 5% of non-directed held orders for a section, provided that the member has identified the top execution venues that in the aggregate received at least 90% of the member's total non-directed held orders for the section.

[18] Similar to SEC Rule 606(a), the types of arrangements referenced above are not an exhaustive list of terms of payment for order flow arrangements or profit-sharing relationships that may influence a broker-dealer's order routing decision that would be required to be disclosed. For example, if a broker-dealer receives a discount on executions in other securities or some other advantage in directing order flow in a specific security to a venue, or if a broker-dealer receives equity rights in a venue in exchange for directing order flow there, then all terms of those arrangements would also be required to be disclosed. Similarly, if a broker-dealer receives variable payments or discounts based on order types and the number of orders sent to a venue, such arrangements would be required to be disclosed. *See* 2018 Amendments Release, 83 FR 58338, 58376 n.397. However, FINRA notes that these are only examples, and a member would be required to disclose any other material aspects of its relationship with each identified venue regardless of whether a particular example is listed in the proposed rule text or otherwise discussed in this proposed rule change.

[19] *See* notes 14 and 15 *supra.*

[20] SEC Rule 606(b)(1) provides that customers may request customer-specific information about the handling of both their held and not held orders, and SEC Rule 606(b)(3) provides that customers may request additional customer-specific information about the handling of their not held orders. FINRA is not proposing parallel customer-specific disclosure requirements for OTC Equity Securities at this time.

[21] The proposed requirement to disclose the percentage of total orders for each section that were not held orders and held orders is the only disclosure requiring any information regarding not held orders, as the remainder of the proposed disclosures apply exclusively to held orders. If a member did not accept any held orders in OTC Equity Securities from customers in a given calendar quarter, it would not be required to publish a report under proposed Rule 6470 for that quarter (even if it accepted orders on a not held basis during that quarter). *See* note 9, *supra.*

[22] For example, FINRA understands that, unlike in the market for NMS Securities where payment for order flow is typically paid as a specified dollar amount per share, payments in the OTC market are predominantly made on a per order basis (with rates typically bucketed by share price category).

Securities on an internet website that is free and readily accessible for at least three years, and proposed FINRA Rule 6470 would similarly require the new OTC Equity Security reports to be published on a website that is free and readily accessible for at least three years. Currently there is not one location where all SEC Rule 606(a) reports are consolidated, although FINRA understands some broker-dealers use vendors that make their client broker-dealers' reports available through common vendor pages. Thus, regulators, investors and others seeking to review the reports often must locate and obtain the reports from various individual broker-dealer or vendor websites.

To make both the existing Rule 606(a) reports and the new OTC Equity Security reports more accessible for regulators, investors and others seeking to analyze and compare the data, FINRA is proposing to require that members provide the reports to FINRA for central publication on the FINRA website (in addition to posting on a public website for at least three years, as required under Rule 606(a) and proposed Rule 6470(a)).[23] Specifically, paragraph (d) of proposed new Rule 6470 would require each member to provide the OTC Equity Security report to FINRA within one month after the end of the quarter addressed in the report in such a manner as may be prescribed by FINRA.[24] Proposed new Rule 6151, entitled ''Disclosure of Order Routing Information for NMS Securities,'' would similarly require each member that is required to publish a report pursuant to SEC Rule 606(a) to provide the report to FINRA, in the manner prescribed by FINRA, within the same time and in the same formats that such report is required to be made publicly available pursuant to SEC Rule 606(a) (*i.e.,* one month after the end of the calendar month addressed in the report). Under both provisions, FINRA would publish such reports on its public website. FINRA will publish both the SEC Rule 606(a) and OTC Equity Security reports in a centralized location on the FINRA website, free of charge and with no restrictions on use of the data.[25]

If the Commission approves the proposed rule change, FINRA will announce the effective date of the proposed rule change in a *Regulatory Notice.* The effective date will be no later than 365 days following publication of the *Regulatory Notice* announcing Commission approval of the proposed rule change.

2. Statutory Basis

FINRA believes that the proposed rule change is consistent with the provisions of Section 15A(b)(6) of the Act,[26] which requires, among other things, that FINRA rules must be designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, and, in general, to protect investors and the public interest.

FINRA believes that the proposed requirement for members to publish order routing disclosures for OTC Equity Securities, similar to what is available under SEC rules for NMS Securities, would provide valuable information for investors and other market participants, academics, regulators and others regarding order routing practices in the OTC market, thereby enhancing the protection of investors and the public interest. In particular, these new disclosures will enable investors to better assess the quality of their broker-dealers' order handling services for these securities, provide more information on the financial incentives that may affect their broker-dealers' routing decisions, and allow investors to better evaluate whether their broker-dealers are effectively managing potential conflicts of interest. The proposed requirements for members to send their disclosure reports for both NMS Securities and OTC Equity Securities to FINRA for centralized publication on the FINRA website will make this important information more accessible for regulators, investors, academics and others seeking to analyze and compare the data, particularly across firms, and would facilitate the ability of FINRA and the SEC to review the data for regulatory purposes.

B. Self-Regulatory Organization's Statement on Burden on Competition

FINRA does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

Economic Impact Assessment

Based on the regulatory need discussed above and summarized below, FINRA has undertaken an economic impact assessment, as set forth below, to analyze the potential economic impacts of the proposed rule change, including potential costs, benefits, and distributional and competitive effects, relative to the current baseline.

Regulatory Need

FINRA believes that in today's markets, where various incentives may impact broker-dealers' order handling decisions, customers have limited access to relevant information to help them assess how their orders are handled, and that different customers may have access to different amounts or categories of relevant information. The proposed requirement for members to publish quarterly order routing disclosures for non-directed held orders in OTC Equity Securities is designed to provide investors with information to better assess the quality of order handling services provided by their broker-dealers and whether their broker-dealers are effectively managing potential conflicts of interest. In addition, requiring members to send both the existing SEC Rule 606(a) disclosures and the proposed OTC Equity Security disclosures to FINRA for centralized publication on the FINRA website would make these disclosures more accessible to investors and others relevant stakeholders.

Economic Baseline

Between October 1 and December 31, 2020, there were 85, 76, and 55 firms[27] quoting domestic OTC Equity Securities, ADRs and foreign ordinaries that are OTC Equity Securities, and

[23] FINRA also intends to engage in investor education efforts to help investors and others understand the purpose, content, and potential limitations of the disclosures.

[24] FINRA would specify details regarding the manner of submission of the reports to FINRA in a *Regulatory Notice* or similar publication. Members would be permitted to use a third-party vendor to assist with both the generation of the reports and transmission to FINRA. However, the member would remain responsible for the reports in all respects, including the accuracy of the disclosures and the timeliness and completeness of the submissions to FINRA. Accordingly, a member would be required to submit a corrected report to FINRA (and publish a corrected report on its publicly accessible website) promptly following the discovery of inaccurate data or other error in a previously submitted or posted report.

[25] As noted above, the SEC has provided guidance that introducing firms may comply with Rule 606(a) by incorporating their clearing firm(s) reports in specified circumstances, and FINRA intends to provide similar guidance with respect to the OTC Equity Security reports required under proposed Rule 6470. *See supra* note 10. To facilitate centralized access to the reports, such introducing firms must provide FINRA with a list of their clearing firm(s) and the hyperlink to the web page where they disclose their clearing firm relationship(s) and adopt the clearing firm(s)'s reports by reference. Each introducing firm relying on this guidance would be required to provide this information to FINRA upon implementation of the proposed rule change and to update FINRA if the information previously provided changes. This information will enable FINRA to provide investors with relevant information for all firms, including introducing firms incorporating clearing firm reports by reference, on FINRA's website.

[26] 15 U.S.C. 78*o*–3(b)(6).

[27] A ''firm'' is any FINRA member that has a Central Registration Depository number.

Canadian-listed securities trading in the U.S. as OTC Equity Securities, respectively. The average number of symbols quoted per firm in each of these respective security categories was: 496, 681, and 260. Furthermore, the average number of quote events per symbol and firm, 37,831, was the largest for Canadian-listed securities that trade OTC in the U.S. as compared to 1,203 for domestic and 25,105 for ADRs and foreign ordinaries.

There are more firms executing trades than providing quotes in OTC Equity Securities. In the fourth quarter of 2020, there were 261, 250, and 196 firms executing trades in domestic, ADRs and foreign ordinaries, and Canadian-listed securities trading in the U.S. as OTC Equity Securities, respectively. The average number of symbols traded per firm was 287, 491, and 195, and the average number of executions per symbol and per firm was 1,215, 1,082, and 1,381 for these respective security categories. Although the average number of executions per symbol per firm was largest for Canadian-listed securities, the average dollar volume per symbol and per firm was largest for the ADRs and foreign ordinaries at $7,687,626, as compared to $3,621,871 for domestic and $2,660,868 for the Canadian-listed securities that trade OTC in the U.S. This reflects the generally lower prices for domestic OTC Equity Securities and Canadian-listed securities that trade OTC in the U.S. as compared to ADRs and foreign ordinary shares.

In the fourth quarter of 2020, there were 560, 573, and 444 firms that routed orders in domestic OTC Equity Securities, ADRs or foreign ordinaries, and Canadian-listed securities that trade as OTC Securities in the U.S, respectively, with approximately 600 unique firms total across the three categories. These numbers represent the potential upper bound on the number of firms by security category that could be required to provide the proposed disclosure reports, as some firms may not handle orders from customers (based on fourth quarter of 2020 data). The average number of symbols routed per firm is 104, 180, and 67, and the average number of orders per symbol and per firm is 170, 124, and 134 for each of the three security categories. Consequently, the largest average number of symbols routed per firm was for ADRs and foreign ordinaries, but the average number of orders per symbol per firm was largest for domestic OTC Equity Securities.

FINRA believes that, at present, customers receive limited information on how members route their orders in OTC Equity Securities, any payments that members receive from execution venues related to the routing of these orders, and the relative order execution quality by member or execution venue. In the absence of regulatory disclosure requirements, any information that customers do receive may be selectively provided to individual customers and is likely not comparable across firms. Moreover, larger customers may receive more information relative to smaller customers, thereby giving the former an informational advantage. OTC Equity Security routing data is currently not required to be publicly available, and no studies have been conducted on the quality of order handling services provided by firms for such securities.

There are, however, studies that examine the benefits of transparency around the implementation of Rules 605 [28] and 606 of Regulation NMS with respect to member routing and venue execution quality for NMS stocks. These studies may inform the potential economic impacts from transparency in the market for OTC Equity Securities, although, as noted above, there are significant differences between the market for NMS Securities and OTC Equity Securities. In addition, as Rules 605 and 606 went into effect at approximately the same time, these studies are unable to distinguish the separate effects of order execution quality disclosure under Rule 605 and that of order routing disclosure under Rule 606 on activity in NMS stocks. After implementation of Rule 605, effective and quoted spreads for NYSE-, AMEX-, and NASDAQ-listed stocks declined significantly.[29] In addition, the implementation of Rules 605 and 606 resulted in broker-dealers increasingly routing orders in NMS stocks to venues that offered better execution quality on the dimensions of effective spreads and fill rates, which suggests these reports contain information that appears useful in routing decisions.[30]

Studies analyzing the market for NMS stocks indicate that broker-dealers may route orders to maximize order flow payments by sending market orders to venues making payments and sending limit orders to venues paying large liquidity rebates. Such routing may not always be in customers' best interests. Make-take fees may lead to agency conflicts and rebate volume pricing tiers may worsen such conflicts further.[31] Theoretical models of the conflict between investors and their broker-dealers, who may be incentivized to route orders based on the take fees charged or rebates paid by exchanges, find that the conflict of interest reduces investor utility.[32] Using Rule 606 data, one study examined broker-dealer routing of non-marketable limit orders in NMS stocks to exchanges offering the largest rebate. This analysis combined with proprietary limit order data found that low-fee (*i.e.,* low-rebate) exchanges fill or fill more rapidly when high-fee (*i.e.,* high-rebate) exchanges do not fill, and non-marketable limit orders earn higher average realized spreads on low-fee than high-fee exchanges.[33]

In the absence of the proposed disclosures, investors may not know where a broker-dealer routes orders for execution or whether the broker-dealer receives payments or rebates from such venues. In addition, in the absence of order routing and payment for order flow information, customers may not possess information necessary to assist them in forming a preference concerning their brokers' routing choices—particularly where customer commission charges have been reduced or eliminated. Furthermore, if customers have information on how brokers route orders and are able to negotiate commissions to more closely represent the broker-dealer's average execution cost for a particular customer's order flow, then customers may be better able to submit the mix of liquidity-supplying and demanding orders to minimize commissions and improve order execution.[34] Even where customers are

[28] Under Rule 605 (formerly 11Ac1–5), the SEC requires market centers that trade NMS Securities to make monthly electronic reports. These reports include information about each market center's quality of executions on a stock-by-stock basis, including how market orders of different sizes are executed relative to the public quotes. These reports also disclose information about effective spreads and the extent to which executions occur at prices better than the public quotes for marketable orders.

[29] *See* Xin Zhao & Kee H. Chung, Information Disclosure and Market Quality: The Effect of SEC Rule 605 on Trading Costs, 42 The Journal of Financial and Quantitative Analysis, 657–682 (2007).

[30] *See* Ekkehart Boehmer, Robert Jennings, & Li Wei, Public Disclosure and Private Decisions: Equity Market Execution Quality and Order Routing, 20 Review of Financial Studies, 315–358 (2007).

[31] *See* James J. Angel, Lawrence E. Harris & Chester S. Spatt, Equity Trading in the 21st Century,'' 1 Quarterly Journal of Finance, 1–53 (2011); Chester S. Spatt, Is Equity Market Exchange Structure Anti-Competitive? (Dec. 28, 2020) Working Paper.

[32] *See* David A. Cimon, Broker Routing Decisions in Limit Order Markets, 54 Journal of Financial Markets, 1386–4181 (2021).

[33] *See* Robert Battalio, Shawn A. Corwin & Robert Jennings, Can Brokers Have It All? On the Relation Between Make-Take Fees and Limit Order Execution Quality, 71 The Journal of Finance, 2193–2238 (2016).

[34] *See* Shawn M. O'Donoghue, Transaction Fees: Impact on Institutional Order Types, Commissions,

unable to negotiate fees, agency issues related to order flow payments may be reduced or eliminated if investors know where their orders are routed. As noted above, while these studies examine the benefits of transparency with respect to NMS stocks and there are significant differences between the market for NMS Securities and the market for OTC Equity Securities, these studies may inform analysis of the potential impacts of the proposed disclosure on the OTC market.

Economic Impacts

Anticipated Benefits

Under the proposed rule change, customers would have more information on the financial incentives that may affect their firms' routing decisions, because the reports would identify the net aggregate amount of any payment for order flow received, payment from any profit-sharing relationship received, transaction fees paid, and transaction rebates received by their firms.

At present, in the absence of order routing reports, customers may be less able to consider indirect costs that may impact execution quality than direct trading costs, such as commissions charged. This is particularly true for retail investors that use the services of zero-commission broker-dealers. Under the proposed rule change, customers may more easily consider indirect and less observable costs, such as transaction fees paid less rebates or payment for order flow, and better assess potential conflicts of interest. Brokerage commissions, if charged, may depend on the amount of payment for order flow received and net make-take fees paid by the firm. For example, members that earn more payment for order flow may pass a portion of this revenue on to customers by offering lower commissions. However, routing solely to maximize rebates or minimize transaction fees may result in lower execution quality than alternative routing strategies and may raise best execution concerns. Without the proposed disclosures, customers may primarily assess the amount of commissions, if charged, when evaluating brokerage service costs. Customers may pay higher net trading costs should zero or lower commission firms offer inferior execution quality. Standardized reports, which would be available on the member's website and centralized on FINRA's website, would allow customers to compare order routing practices across different firms and observe changes in a firm's routing behavior over time. Customers would be able to better compare indirect trading costs and whether payment for order flow received and net transaction fees paid, considering rebates, may be affecting the routing decisions of some firms more than others or causing changes in routing behavior over time. The information in these reports would permit customers to evaluate firms' routing decisions more effectively and be better informed in making choices among firms. Dividing OTC Equity Securities into separate sections depending on whether they are domestic, ADRs or foreign ordinaries, or Canadian-listed OTC Equity Securities would provide customers with meaningful categories and potentially make the information more useful than if all securities were presented in one group.

FINRA believes that direct benefits to customers stemming from the proposed standardized reports may be limited by a customer's ability to interpret the information in the reports or compare the reports across different members or over time. However, customers may also benefit indirectly through changes in a firm's behavior. A firm may use the standardized reports to compare its order routing to that of competing firms, and subsequently, to improve its order execution quality. Thus, firms that do not route solely based on payment for order flow received, net transaction fees paid (inclusive of rebates), or provide relatively better order execution quality may better compete for customers based on not receiving rebates or providing better order execution quality.[35] In addition, academic or industry researchers may analyze the data in the proposed public reports, which will be centralized on FINRA's website, and make their findings describing differences in broker-dealer routing practices public.

Because FINRA members would be required to submit their existing Rule 606(a) reports to FINRA for central publication on the FINRA website, investors and academic and other industry researchers may more easily access the SEC Rule 606(a) reports, which should make it easier for users to examine data in SEC Rule 606(a) reports across broker-dealers. The reporting and centralization of both the new OTC Equity Security reports and the existing Rule 606(a) reports should also ease FINRA's access to the reported data for regulatory purposes, thereby reducing FINRA's costs.

Anticipated Costs

Members may incur fixed costs, such as programming, to create the initial proposed reports. These initial costs may vary depending on whether firms collect the data and produce the reports in-house or outsource the process to a third party. Members may pay costs to identify which orders are non-directed and submitted on a held basis and determine the net aggregate amount of any payment for order flow received and net rebates received in total and per order. To the extent that a member already has systems in place to create reports required for NMS Securities under Rule 606(a), which is probable in most cases, then these initial fixed costs may be relatively lower for such members, although the extent to which these costs would be lower for such firms would depend on the degree to which their existing systems for NMS Securities' disclosures may be used for OTC Equity Securities. Once the system to create the proposed reports is built, there would be fixed costs for maintaining the system and on-going compliance costs, and variable costs for creating and posting the publicly available quarterly reports and for transmitting the reports to FINRA.

In addition, firms that route orders in OTC Equity Securities may re-evaluate their best execution evaluation methodologies and, if deemed beneficial, may choose to incorporate information from the proposed publicly available reports posted by competing firms, which may or may not involve costs to the firm depending on how a firm chooses to use this information.[36] Furthermore, as noted by the Commission with respect to new disclosure requirements under Rule 606(b)(3), ''[g]iven that broker-dealers will be aware of the metrics to be used a priori, they might route not held orders in a manner that promotes a positive reflection on their respective services but that may be suboptimal for their customers.'' [37] FINRA notes the same possibility in connection with the proposed rule change requiring the disclosure of OTC order handling disclosures. However, FINRA also notes

and Execution Quality, 60 Journal of Financial Markets (2022).

[35] In light of differences between the market for NMS Securities and the market for OTC Equity Securities, including for example the absence of a centralized, SRO-disseminated national best bid and offer in the OTC market, FINRA is not proposing execution quality disclosure requirements for OTC Equity Securities at this time.

[36] While firms that route orders in OTC Equity Securities may re-evaluate their best execution evaluation methodologies and incorporate information from the proposed reports, the proposed new OTC Equity Security order routing disclosure reports themselves would not alter a firm's best execution obligations.

[37] *See* 2018 Amendments Release, 83 FR 58338, 58425.

any such effects would be constrained by a firm's obligations under FINRA Rule 5310. In addition, to the extent that the proposal increases costs to members, particularly smaller firms, they may attempt to recoup costs by increasing fees for customers or modifying the scope of services offered for OTC Equity Securities.

Further, if firms stop or limit routing orders to venues paying rebates or making payments for order flow given the existence of the proposed reports, then these venues may reduce or eliminate these financial incentives as volumes decline, which could in turn impact the extent to which a market participant is willing to provide liquidity at such venues, potentially resulting in fewer quotes, wider bid-ask spreads, or fewer shares posted at such venues. In addition, the cost of capital for firms that issue OTC Equity Securities may increase if their securities become less liquid. Because members will be responsible for submitting SEC Rule 606(a) reports currently required for NMS Securities under Regulation NMS to FINRA, they will bear either a direct cost to send the reports to FINRA or an indirect cost if an agent sends the report on their behalf. FINRA believes that introducing firm members that choose to rely on the proposed guidance [38] would incur lower costs compared to preparing and providing the actual reports on a quarterly basis on their own or through a third-party vendor.

Alternatives Considered

No other alternatives were considered for the proposed amendments.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The proposed rule change was published for comment in *Regulatory Notice* 21–35 (October 2021). Five comments were received in response to the *Regulatory Notice.*[39] A copy of the *Regulatory Notice* is available on FINRA's website at *http://www.finra.org.* Copies of the comment letters received in response to the *Regulatory Notice* are also available on FINRA's website. The comments are summarized below.

NASAA supported the proposed rule change, stating that it is appropriately tailored to reveal potential conflicts of interest and would bring additional transparency to trading practices in the OTC market.[40] NASAA also expressed support for FINRA's publication of order routing reports on its website, noting that centralization of the reports would allow investors to make comparisons easily, help inform and facilitate regulatory decisions, and help FINRA analyze compliance with the proposed rule, discover best reporting practices to share with its members, perform comparisons to facilitate risk-based examination selections, and determine whether disclosures give rise to the need for investigation.[41] FINRA agrees and, as discussed above, is proposing to publish both the new OTC Equity Security reports and existing SEC Rule 606(a) reports in a centralized location on its website, free of charge and without usage restrictions. Finally, NASAA expressed its belief that investor education is necessary to make the reports useful, and accordingly suggested that FINRA develop and post information for investors on how to read and interpret the data. Alternatively, NASAA suggested that FINRA could develop standard educational materials that firms can either link to or be required to make available with the reports.[42] FINRA agrees that investor education would be useful and, as noted above, intends to engage in investor education efforts regarding the purpose, content, and potential limitations of the disclosures.[43]

Fidelity also supported the proposed rule change, stating that it largely accomplishes the goals of providing transparency into broker routing and economic practices in OTC Equity Securities, an asset class that has experienced significant growth but remains opaque.[44] Fidelity also made several recommendations to enhance the effectiveness of the proposed rule change. First, Fidelity recommended that FINRA and the SEC should consider how various order routing disclosure reports, including SEC Rules 605 and 606 reports, are used in the marketplace and could be used together, suggesting that FINRA and the SEC should coordinate their oversight of order routing reports to ensure consistency in process and interpretation.[45] FINRA agrees with and, as described above, has sought to align the form and content of the new OTC Equity Security reports as closely as possible with the existing Rule 606(a) reports, unless there was a reason for the content to differ due to the unique characteristics of the OTC market. FINRA believes that this approach will assist in ensuring consistency in the process for generating the reports and regulatory interpretation concerning the reporting framework. FINRA also expects to continue its engagement with the SEC regarding order routing and execution quality information more broadly.

Second, Fidelity recommended that FINRA make publicly available a list of OTC Equity Securities appearing in each section of the proposed OTC Equity Security reports, and provide further clarity concerning the definition of market center and fees to be disclosed.[46] As noted above, FINRA will publish a list of the OTC Equity Security symbols that fall under each category to assist members in generating the reports and provide consistency across reports. FINRA has also provided clarifications regarding the scope of venues that should be disclosed on the reports and the types of fees that should be included.[47] FINRA will continue to engage with members to provide additional guidance on these and other issues as appropriate.

Third, Fidelity stated that FINRA should explore obtaining data for all, or part, of the proposed OTC Equity Security reports from broker-dealer CAT submissions.[48] FINRA continues to believe that the most efficient and comprehensive means of providing the data included in the OTC Equity Security order routing disclosures is for members to generate the reports directly.

Finally, Fidelity expressed support for FINRA to consolidate all order routing reports on a centralized website and make this content available without cost.[49] As discussed above, FINRA is proposing to publish both the new OTC Equity Security reports and existing SEC Rule 606(a) reports in a centralized

[38] *See supra* notes 10 and 25.

[39] *See* Comment submission from Keith L Hickman, dated October 7, 2021; letter from Howard Meyerson, Managing Director, Financial Information Forum, to Jennifer Piorko Mitchell, Office of the Corporate Secretary, FINRA, dated December 2, 2021 (''FIF Letter''); letter from Derrick Chan, Head of Equity Trading and Sales, Fidelity Investments, to Jennifer Piorko Mitchell, Office of the Corporate Secretary, FINRA, dated December 6, 2021 (''Fidelity Letter''); letter from Michelle Bryan Oroschakoff, Chief Legal Officer, LPL Financial, to Jennifer Piorko Mitchell, Office of the Corporate Secretary, FINRA, dated December 6, 2021 (''LPL Letter''); and letter from Melanie Senter Lubin, President, North American Securities Administrators Association, Inc., to Jennifer Piorko Mitchell, Office of the Corporate Secretary, FINRA, dated December 6, 2021 (''NASAA Letter'').

[40] *See* NASAA Letter at 1–3.

[41] *See supra* note 40 at 3–4.

[42] *See supra* note 40 at 5.

[43] *See supra* note 23.

[44] *See* Fidelity Letter at 1–2.

[45] *See supra* note 44 at 2–3.

[46] *See supra* note 44 at 3–4.

[47] *See supra* notes 16 and 18.

[48] *See supra* note 44 at 4–5.

[49] *See supra* note 44 at 5.

location on its website, free of charge and without usage restrictions.

FIF neither supported nor opposed the proposed rule change but provided comments focused on achieving the most effective implementation in the event that FINRA moves forward with the proposed rule change. FIF first provided its views regarding the entity that should be reported as the ''venue'' on the reports when there are multiple levels of routing for an order, including the requirement to ''look-through'' to the execution venue.[50] FIF stated that, when a customer-facing broker-dealer routes an order to a second broker-dealer, the customer-facing broker-dealer should report on its financial arrangement with the second broker-dealer instead of the fee arrangement between the second broker-dealer and that downstream venue. FIF stated that there are many scenarios where a customer-facing broker-dealer will route an OTC Equity Security order to another broker-dealer that is neither a market maker nor an alternative trading system and therefore the order is further routed by the receiving broker-dealer. In these situations, FIF argued that the customer-facing broker-dealer should report the second broker-dealer on any reports instead of the final downstream venue. Reporting the final downstream execution venue, *i.e.,* the ''look-through'' requirement, would ignore any payment for order flow made by the second broker-dealer to the customer-facing broker. FIF also suggested modifying the proposed rule change such that any reference to ''venue'' be changed to ''venue or broker'' and any reference to ''routed for execution'' be changed to ''routed'' or ''routed for execution or further routing'' or ''routed for execution (by the recipient or another party).'' FIF further stated that the look-through requirement would greatly increase the cost of the report due to the costs associated with coordination between the customer-facing broker-dealer and the second broker-dealer that routes to a venue for execution.[51]

Consistent with the requirements of SEC Rule 606(a), FINRA's proposal would cover the venues to which non-directed held orders in OTC Equity Securities were ''routed for execution.'' As discussed above, the SEC has provided guidance in the SEC Rule 606(a) context that, if a broker-dealer routes orders to another broker-dealer, that receiving broker-dealer would be considered to be the relevant venue if that receiving broker-dealer executes orders. However, if the receiving broker-dealer does not execute orders, it would not be a venue to which orders were ''routed for execution.'' Rather, the venue to which the receiving broker-dealer subsequently routed the orders for execution (including child orders) would be the relevant venues for SEC Rule 606(a) reporting purposes. Further, while the reporting responsibility remains with the customer-facing broker-dealer, the customer-facing broker-dealer may contract with the receiving broker-dealer for assistance in meeting its reporting responsibilities.[52] FINRA continues to believe that this aspect of the proposed order routing disclosures for OTC Equity Securities should be consistent with the SEC Rule 606(a) disclosures for NMS Securities, including with respect to the ''look-through'' requirement when a receiving broker-dealer does not execute orders. FINRA believes that aligning the scope of the disclosures with the requirements of SEC Rule 606(a) would reduce the burden of the new disclosure requirements because members already have experience with SEC Rule 606(a) and may be able to utilize existing systems and arrangements with receiving broker-dealers to provide the disclosures for OTC Equity Securities. Further, because the purpose of the proposed disclosures—providing information about members' orders routing practices and potential conflicts of interest related to execution venues—is the same as the purpose of SEC Rule 606(a) for NMS Securities, FINRA believes that the same types of venues should be covered by the new reports for OTC Equity Securities.

FIF also responded to a number of specific questions posed in *Regulatory Notice* 21–35.[53] As an initial matter, FIF agreed with a number of aspects of the proposed rule change, including (i) the quarterly reporting timeframe of the reports; (ii) not providing a separate reporting category for grey market securities; (iii) limiting the proposed reports to held orders in OTC Equity Securities; (iv) not breaking out the reports by market orders, marketable limit orders, non-marketable limit orders, and other orders; (v) requiring reporting of payments per order, rather than per share; (vi) not adopting customer-specific held order disclosures, like those required under SEC Rule 606(b)(3), at this time; and (vii) not adopting execution quality disclosures, like those required under SEC Rule 605, at this time.

FIF requested that FINRA incorporate a *de minimis* venue exception parallel to the exemptive relief that the SEC has provided with respect to the SEC Rule 606(a) reports. As noted above, FINRA agrees and has included a parallel exception in the proposed rule change.[54]

FIF also expressed support for centralized publication of SEC Rule 606(a) reports and, if adopted, the proposed OTC Equity Security reports on the FINRA website (or another third-party website in a manner that can be accessed by all market participants at no cost), and further recommended that the SEC, FINRA, the other self-regulatory organizations and FINRA CAT consider how current reporting systems, such as the CAT, can be leveraged to reduce the general reporting burden for firms. As discussed above, FINRA is proposing to publish both the new OTC Equity Security reports and existing SEC Rule 606(a) reports in a centralized location on its website, free of charge and without usage restrictions. However, FINRA is not proposing to use CAT data for the proposed disclosure requirements in light of restrictions on the use of CAT data and FINRA's continued belief that, as for SEC Rule 606(a) reports, the most efficient method to create and publish the required disclosures is for members to provide the routing information directly.

FIF stated that the proposed categories of OTC Equity Securities are appropriate and recommended that FINRA publish and maintain a file of which symbols are included in each category. As noted above, FINRA will publish a list of the OTC Equity Security symbols that fall under each category to assist members in generating the reports and provide consistency across reports.

FIF stated that the proposed disclosures may have unintended consequences, as increased transparency may lead broker-dealers to change how they route held orders in OTC Equity Securities in ways that may be suboptimal for customers on execution quality dimensions that are less easily observable. To address this concern, FIF suggested that FINRA could publish guidance to investors on the purpose, content, and potential limitations of the reports. While FINRA does not believe that the transparency will likely result in suboptimal executions, FINRA intends to, as appropriate, provide members, investors, and others with information

[50] *See* FIF Letter at 1–3.

[51] *See supra* note 50 at 3.

[52] *See* SEC Division of Trading and Markets, Responses to Frequently Asked Questions Concerning Rule 606 of Regulation NMS, Question 12.01.

[53] *See* FIF Letter at 3–9.

[54] *See supra* note 17.

about the purpose, content, and potential limitations of the reports.

FIF further stated that the industry requires a significant time period for implementation, including sufficient time for industry members to identify and obtain guidance from FINRA on applicable interpretive questions. FINRA intends to provide an appropriate amount of time for implementation of the proposed rule change and will work with the industry to provide guidance as appropriate on interpretive questions. In particular, FIF requested that FINRA meet with industry members to discuss how the proposed routing disclosures should be applied to orders executed through OTC Link, and also requested that FINRA provide additional guidance on the level of detail required for the material aspects disclosure. FINRA intends to continue to engage with members and other interested parties prior to implementation of the proposed rule change, including to discuss order routing disclosures in scenarios involving OTC Link. FINRA also intends to provide guidance as appropriate on other interpretive questions, including the content of the material aspects disclosure. However, FINRA notes that it would generally expect the level of detail included in the material aspects disclosures to be consistent with that provided in SEC Rule 606(a) reports for NMS Securities.

FIF generally agreed with the proposed content of the OTC Equity Security disclosure reports, but recommended removing the requirement that members report the number of directed orders because the routing decision in such cases is outside the control of the broker-dealer. FINRA notes that, as described above and consistent with SEC Rule 606(a), the proposed disclosures would apply only to non-directed held orders. The proposed reports would include aggregate statistics regarding the percentage of total orders that were held and not held orders, and the percentage of held orders that were non-directed orders, but no other information about directed orders would be required.

Finally, FIF stated that its members are divided on whether the reporting requirements should include routes to brokers and venues outside the U.S. FIF recommended that multiple approaches should be permitted and that the reporting firm should indicate which approach was adopted on the web page accompanying the routing reports. In any case, FIF stated that, if a foreign issuer does not have F shares in the U.S., the order should not be reportable. FINRA believes that, consistent with SEC Rule 606(a), the OTC Equity Security disclosures should include information about venues where a member's orders are routed for execution, regardless of the location of such venue. Particularly where orders are non-directed, the member has discretion to choose where it routes orders for execution; therefore, permitting a member to omit foreign venues could raise arbitrage concerns and provide incomplete information to investors. Moreover, information about incentives and potential conflicts of interest is just as relevant where an execution venue is located abroad. With respect to F shares, FINRA notes that orders in any security that meets the definition of OTC Equity Security would be included in the reports regardless of the location of the issuer.

LPL did not support the proposed rule change, stating that, while LPL supports efforts to provide greater transparency as to the handling of orders, the proposed rule change would impose a significant burden on firms without providing useful information to investors.[55] LPL stated that the proposed rule change would have limited benefits as compared to SEC Rule 606(a) for NMS Securities, which LPL believes can provide investors with useful information because it can be combined with order execution information available pursuant to SEC Rule 605; by contrast, the proposed OTC Equity Security disclosures would not have parallel execution quality disclosures.[56]

FINRA believes that the proposed order routing disclosures will provide investors and other market participants with useful information, even in the absence of Rule 605-like disclosures at this time.[57] FINRA believes the proposed order routing disclosures will facilitate investor understanding of where their brokers are routing orders and the relationships their brokers have with those execution venues. In addition, FINRA notes that SEC Rule 606(a) includes information about order routing practices for NMS Securities that are options, and options are not included in the execution quality disclosures under SEC Rule 605.

[55] *See* LPL Letter at 1.

[56] *See supra* note 55 at 1–2.

[57] In light of differences between the market for NMS Securities and OTC Equity Securities, including for example the absence of a centralized, SRO-disseminated national best bid and offer in the OTC market, FINRA is not proposing Rule 605-like execution quality disclosure requirements for OTC Equity Securities at this time. FINRA will continue to consider whether additional disclosures would provide useful information for investors in OTC Equity Securities.

LPL also stated its belief that the proposed rule change would subject firms to costly burdens, including internal technology costs to identify and gather the needed data, vendor costs to prepare quarterly reports, and employee time to implement and supervise disclosures.[58] Given that OTC Equity Securities are a very small part of LPL's core business, LPL stated that these additional burdens may have a chilling effect and cause firms to stop accepting orders for OTC Equity Securities. As discussed above, FINRA acknowledges that members would incur costs to capture the required data, generate the reports, publish the reports, and transmit the reports to FINRA for centralization publication. FINRA believes that such costs would be reduced for introducing firms that choose to rely on the guidance discussed above.[59] In any case, FINRA continues to believe that the costs associated with the proposal are outweighed by the benefits to investors and the market of the transparency provided by the proposed OTC Equity Security disclosures.

Finally, LPL stated that imposing the additional costs of the proposed OTC Equity Security disclosures on firms that do not receive payment for order flow would be both unfair and unproductive, and therefore requested that, if FINRA adopts the proposed rule change, the proposed rule change include an exemption for firms that do not receive payment for order flow.[60] FINRA notes that, while payment for order flow arrangements are an important component of the information that would be required to be disclosed under the proposed rule change, the proposed disclosures also include information about other payments and arrangements that members may have with execution venues that may influence a member's order routing decision. FINRA continues to believe that the proposed disclosures would be valuable for investors and other market participants more broadly, regardless of whether a particular member receives payment for order flow, because the proposed disclosures would provide investors with a better understanding of where their brokers are routing orders and the overall relationships their brokers have with those execution venues.

[58] *See* LPL Letter at 2. LPL stated that it expects the initial costs to implement the proposed rule change would be similar to the cost of complying with recent amendments to SEC Rule 606.

[59] *See supra* notes 10 and 25.

[60] *See* LPL Letter at 2–3.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 45 days of the date of publication of this notice in the **Federal Register** or within such longer period (i) as the Commission may designate up to 90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

(A) by order approve or disapprove such proposed rule change, or

(B) institute proceedings to determine whether the proposed rule change should be disapproved.

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–FINRA–2022–031 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–FINRA–2022–031. 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 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 a.m. and 3 p.m. Copies of such filing also will be available for inspection and copying at the principal office of FINRA. All comments received will be posted without change. Persons submitting comments are cautioned that we do not redact or edit personal identifying information from comment submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–FINRA–2022–031 and should be submitted on or before December 27, 2022.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[61]

Sherry R. Haywood,

Assistant Secretary.

[FR Doc. 2022–26445 Filed 12–5–22; 8:45 am]

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SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–96408; File No. SR–NYSE–2022–54]

Self-Regulatory Organizations; New York Stock Exchange LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend Listed Company Manual Section 302.00

November 30, 2022.

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (the ''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on November 21, 2022, New York Stock Exchange LLC (''NYSE'' or the ''Exchange'') filed with the Securities and Exchange Commission (the ''Commission'') the proposed rule change as described in Items I and II below, which Items have been prepared by the self-regulatory organization. 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 Listed Company Manual Section 302.00 to exclude Exchange-Traded Fund Shares listed pursuant to Rule 5.2(j)(8) from the obligation to hold annual shareholders' meetings. 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 the Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend Listed Company Manual Section 302.00 to exclude Exchange-Traded Fund Shares listed pursuant to Rule 5.2(j)(8) from the obligation to hold annual shareholders' meetings. Exchange-Traded Fund shares are Derivative Securities Products[3] permitted to operate in reliance on Rule 6c–11 (''Rule 6c–11'') under the Investment Company Act of 1940 (''1940 Act'').[4]

Listed Company Manual Section 302.00 provides that companies listing common stock or voting preferred stock and their equivalents are required to hold an annual shareholders' meeting for the holders of such securities during each fiscal year. Listed Company Manual Section 302.00 currently exempts, among other securities, Exchange-Traded Funds (''ETFs'') listed under Rule 5.2–(j)(3) (Investment Company Units) or Commentary .01 to Rule 8.600 (Managed Fund Shares) and other derivative securities from the Exchange's annual shareholder meeting requirement.

The Exchange proposes to amend Section 302.00 of the Listed Company Manual to add Exchange-Traded Fund Shares listed pursuant to Rule 5.2(j)(8) to the list of securities for which the requirements of Section 302.00 regarding annual shareholders' meetings do not apply. The proposed change is based on, and would align Section 302.00 of the Listed Company Manual with, NYSE Arca Rule 5.3–E(e), which

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[61] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] The term ''Derivative Securities Product'' is defined in Rule 1.1(k) to mean a security that meets the definition of ''derivative securities product'' in Rule 19b4(e) under the Exchange Act. 17 CFR 240.19b–4(e).

[4] *See* Release Nos. 33–10695; IC–33646; File No. S7–15–18 (Exchange-Traded Funds) (September 25, 2019), 84 FR 57162 (October 24, 2019).

exempts Exchange-Traded Fund Shares listed under NYSE Arca Rule 5.2–E(j)(8), from the shareholder/annual meeting requirements. NYSE Rule 5.2(j)(8) and NYSE Arca Rule 5.2–E(j)(8) are substantially similar.[5]

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with Section 6(b)(5) of the Exchange Act,[6] in that it is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in facilitating transactions in securities, to remove impediments to and perfect the mechanism of a free and open market and a national market system and, in general, to protect investors and the public interest.

The Exchange believes that the proposal to amend Listed Company Manual Section 302.00 to include Exchange-Traded Fund Shares listed pursuant to Rule 5.2(j)(8) among the securities exempted from the annual shareholders' meeting requirement is designed to prevent fraudulent and manipulative acts and practices and to remove impediments to and perfect the mechanism of a free and open market and a national market system because such securities, like ETFs and other derivative securities currently exempted from the requirements of Listed Company Manual Section 302.00, would remain subject to the same requirements currently applicable to other 1940 Act-registered investment company securities (*e.g.,* Investment Company Units, Managed Fund Shares, and Portfolio Depositary Receipts). As noted, the proposed change is based on NYSE Arca Rule 5.3–E(e), which exempts Exchange-Traded Fund Shares listed under the listing standards for such products under NYSE Arca Rule 5.2–E(j)(8) (Exchange-Traded Fund Shares), from substantially similar requirements with respect to annual meetings. The proposed change would thus make Listed Company Manual Section 302.00 consistent with NYSE Arca Rule 5.3–E(e), resulting in similar treatment of ETFs permitted to operate in reliance on Rule 6c–11 under the 1940 Act across affiliated exchanges for purposes of the annual meeting requirement.

B. Self-Regulatory Organization's Statement on Burden on Competition

In accordance with Section 6(b)(8) of the Act,[7] 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 rule change would facilitate the listing and trading of Exchange-Traded Fund Shares listed pursuant to Rule 5.2(j)(8) on the Exchange, thereby enhancing competition among both market participants and listing venues, to the benefit of investors and the marketplace.

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 Exchange has filed the proposed rule change pursuant to Section 19(b)(3)(A)(iii) of the Act[8] and Rule 19b–4(f)(6) thereunder.[9] Because the proposed rule change does not: (i) significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative prior to 30 days from the date on which it was filed, or such shorter time as the Commission may designate, if consistent with the protection of investors and the public interest, the proposed rule change has become effective pursuant to Section 19(b)(3)(A) of the Act[10] and Rule 19b–4(f)(6)(iii) thereunder.[11]

A proposed rule change filed under Rule 19b–4(f)(6)[12] normally does not become operative prior to 30 days after the date of the filing. However, pursuant to Rule 19b–4(f)(6)(iii),[13] the Commission may designate a shorter time if such action is consistent with the protection of investors and the public interest. The Exchange has asked the Commission to waive the 30-day operative delay so that the proposal may become operative immediately upon filing.

The Commission believes that waiver of the operative delay is consistent with the protection of investors and the public interest because it will allow the Exchange to promptly provide its listed ETFs the same exemption from annual meeting requirements that currently applies to ETFs listed on NYSE Arca. Accordingly, the Commission hereby waives the 30-day operative delay and designates the proposal operative upon filing.[14]

At any time within 60 days of the filing of such 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. If the Commission takes such action, the Commission shall institute proceedings under Section 19(b)(2)(B)[15] of the Act to determine whether the proposed rule change should be approved or disapproved.

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–NYSE–2022–54 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–NYSE–2022–54. 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/*

[5] *See* Securities Exchange Act Release No. 91029 (February 1, 2021), 86 FR 8420, 8424 (February 5, 2021) (SR–NYSE–2020–86) (Order Approving a Proposed Rule Change To Adopt NYSE Rule 5.2(j)(8) Governing the Listing and Trading of Exchange-Traded Fund Shares).

[6] 15 U.S.C. 78f(b)(5).

[7] 15 U.S.C. 78f(b)(8).

[8] 15 U.S.C. 78s(b)(3)(A)(iii).

[9] 17 CFR 240.19b–4(f)(6).

[10] 15 U.S.C. 78s(b)(3)(A).

[11] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change, along with a brief description and text of the proposed rule change, at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

[12] 17 CFR 240.19b–4(f)(6).

[13] 17 CFR 240.19b–4(f)(6)(iii).

[14] For purposes only of accelerating the operative date of this proposal, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. 15 U.S.C. 78c(f).

[15] 15 U.S.C. 78s(b)(2)(B).

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 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 office of the Exchange. All comments received will be posted without change. Persons submitting comments are cautioned that we do not redact or edit personal identifying information from comment submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NYSE–2022–54 and should be submitted on or before December 27, 2022.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[16]

Sherry R. Haywood,

Assistant Secretary.

[FR Doc. 2022–26439 Filed 12–5–22; 8:45 am]

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SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–96413; File No. SR–GEMX–2022–11]

Self-Regulatory Organizations; Nasdaq GEMX, LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend the Definition of Short Term Option Series

November 30, 2022.

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 November 18, 2022, Nasdaq GEMX, LLC (''GEMX'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I and II 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 Options 1, General Provisions. The Exchange also proposes amendments within General 2, Organization and Administration.

The text of the proposed rule change is available on the Exchange's website at *https://listingcenter.nasdaq.com/rulebook/gemx/rules,* 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 Exchange 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 these 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 aspects 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 description of the term ''Short Term Option Series'' within Options 1, Section 1, Definitions, to conform the term to Nasdaq ISE, LLC's (''ISE'') term of Short Term Option Series which was recently amended.[3] The Exchange also proposes certain non-substantive amendments. Each change is described below.

Short Term Option Series

Options 1, Section 1(a)(48) describes the term ''Short Term Option Series'' as follows:

The term ''Short Term Option Series'' means a series in an option class that is approved for listing and trading on the Exchange in which the series is opened for trading on any Monday, Tuesday, Wednesday, Thursday, or Friday that is a business day and that expires on the Monday, Wednesday or Friday of the following business week that is a business day, or, in the case of a series that is listed on a Friday and expires on a Monday, is listed one business week and one business day prior to that expiration. If a Tuesday, Wednesday, Thursday or Friday is not a business day, the series may be opened (or shall expire) on the first business day immediately prior to that Tuesday, Wednesday, Thursday or Friday. For a series listed pursuant to this section for Monday expiration, if a Monday is not a business day, the series shall expire on the first business day immediately following that Monday.

ISE's Options 4 rules were recently amended to expand the Short Term Option Series program to permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program.[4] In conjunction with that change, ISE amended its definition of Short Term Option Series, within Options 1, Section 1(a)(49), to accommodate the listing of options series that expire on Tuesdays and Thursdays.[5] Specifically, the Exchange added Tuesday and Thursday to the permitted expiration days, which currently include Monday, Wednesday, and Friday, that it may open for trading.

At this time, the Exchange proposes to amend the term ''Short Term Option Series'' at Options 1, Section 1(a)(48) to provide,

The term ''Short Term Option Series'' means a series in an option class that is approved for listing and trading on the Exchange in which the series is opened for trading on any Monday, Tuesday, Wednesday, Thursday, or Friday that is a business day and that expires on the Monday, Tuesday, Wednesday, Thursday, or Friday of the following business week that is a business day, or, in the case of a series that is listed on a Friday and expires on a Monday, is listed one business week and one business day prior to that expiration. If a Tuesday, Wednesday, Thursday or Friday is not a business day, the series may be opened (or shall expire) on the first business day immediately prior to that Tuesday, Wednesday, Thursday or Friday. For a series listed pursuant to this section for Monday expiration, if a Monday is not a business day, the series shall expire on the first business day immediately following that Monday.

Today, GEMX's listing rules permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program.[6]

[16] 17 CFR 200.30–3(a)(12), (59).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 96281 (November 9, 2022), 87 FR 68769 (November 16, 2022) (SR–ISE–2022–18) (Order Granting Approval of a Proposed Rule Change to Amend the Short Term Option Series Program).

[4] *See* note 3 above. GEMX's Options 4 Rules are incorporated by reference to ISE's Options 4 Rules.

[5] *See* note 3 above.

[6] GEMX's Options 4 Rules are incorporated by reference to ISE's Options 4 Rules and therefore the approval of ISE's Options 4 rules permits the listing and trading of options series with Tuesday and

Continued

Other Non-Substantive Amendments

The Exchange proposes to make other amendments to reserve certain sections of the Rulebook. These sections contain content in other Nasdaq affiliated rulebooks. To harmonize the section numbers across the Nasdaq affiliated markets, the Exchange proposes to reserve General 2, Sections 23 and 24. These amendments are non-substantive.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act,[7] in general, and furthers the objectives of Section 6(b)(5) of the Act,[8] in particular, in that it is designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general to protect investors and the public interest.

Short Term Option Series

The Exchange's proposal to amend the term ''Short Term Option Series'' at Options 1, Section 1(a)(48) to reflect the recent change [9] to GEMX's listing rules to permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program is consistent with the Exchange Act. This proposal will align the description of Short Term Option Series within Options 1, Section 1(a)(48) to the expirations permitted within the Short Term Option Series Program within Supplementary .03(a) to Options 4, Section 5.

Other Non-Substantive Amendments

The Exchange's proposal to reserve certain sections of the Rulebook, namely General 2, Sections 23 and 24, to harmonize section numbers across the Nasdaq affiliated markets is non-substantive.

B. Self-Regulatory Organization's Statement on Burden on Competition

The proposed rule change does not impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

Short Term Option Series

The Exchange's proposal to amend the term ''Short Term Option Series'' at Options 1, Section 1(a)(48) to reflect the recent change [10] to GEMX's listing rules to permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program does not impose an undue burden on competition, rather this proposal will align the description of Short Term Option Series within Options 1, Section 1(a)(48) to the expirations permitted within the Short Term Option Series Program within Supplementary .03(a) to Options 4, Section 5.

Other Non-Substantive Amendments

The Exchange's proposal to make other amendments to reserve certain sections of the Rulebook, namely General 2, Sections 23 and 24, to harmonize section numbers across the Nasdaq affiliated markets is non-substantive.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The Exchange has filed the proposed rule change pursuant to Section 19(b)(3)(A)(iii) of the Act [11] and Rule 19b–4(f)(6) thereunder.[12] Because the foregoing proposed rule change does not: (i) significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A)(iii) of the Act [13] and subparagraph (f)(6) of Rule 19b–4 thereunder.[14] The Exchange has stated that the Options 4 listing rules were recently amended to expand the Short Term Option Series program to permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program,[15] and that waiver of the 30-day operative delay will allow the Exchange to conform the definition of a Short Term Option Series to the Options 4 listing rules. The Commission believes that waiver of the 30-day operative delay is consistent with the protection of investors and the public interest because the proposed rule change does not raise any new or novel issues. Accordingly, the Commission hereby waives the operative delay and designates the proposed rule change operative upon filing.[16]

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. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or disapproved.

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–GEMX–2022–11 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–GEMX–2022–11. 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

Thursday expirations for options on SPY and QQQ on GEMX.

[7] 15 U.S.C. 78f(b).

[8] 15 U.S.C. 78f(b)(5).

[9] *See* note 3 above.

[10] *See* note 3 above.

[11] 15 U.S.C. 78s(b)(3)(A)(iii).

[12] 17 CFR 240.19b–4(f)(6).

[13] 15 U.S.C. 78s(b)(3)(A)(iii).

[14] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6)(iii) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change, along with a brief description and text of the proposed rule change, at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

[15] *See supra* note 4.

[16] For purposes only of waiving the 30-day operative delay, the Commission has also considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

communications relating to the 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 office of the Exchange. All comments received will be posted without change. Persons submitting comments are cautioned that we do not redact or edit personal identifying information from comment submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–GEMX–2022–11, and should be submitted on or before December 27, 2022.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[17]

Sherry R. Haywood,

Assistant Secretary.

[FR Doc. 2022–26443 Filed 12–5–22; 8:45 am]

BILLING CODE 8011–01–P

[17] 17 CFR 200.30–3(a)(12), (59).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–96412; File No. SR–NASDAQ–2022–066]

Self-Regulatory Organizations; The Nasdaq Stock Market LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend the Definition of Short Term Option Series

November 30, 2022.

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 November 18, 2022, The Nasdaq Stock Market LLC (''Nasdaq'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I and II 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 certain rule text within General 2, Organization and Administration. Additionally, the Exchange proposes to amend The Nasdaq Options Market LLC (''NOM'') rules at Options 1, General Provisions; Options 4A, Options Index Rules; and Options 10, Doing Business with the Public.

The text of the proposed rule change is available on the Exchange's website at *https://listingcenter.nasdaq.com/rulebook/nasdaq/rules,* 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 Exchange 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 these 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 aspects 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 description of the term ''Short Term Option Series'' within NOM Options 1, Section 1, Definitions, to conform the term to Nasdaq ISE, LLC's (''ISE'') term of Short Term Option Series which was recently amended.[3] The Exchange also proposes to amend certain rule text within NOM Options 4A, Section 12, Terms of Index Options Contracts, related to the Short Term Option Series Program. Finally, the Exchange propose certain other non-substantive amendments. Each change is described below.

Short Term Option Series

Options 1, Section 1(a)(57) describes the term ''Short Term Option Series'' as follows:

The term ''Short Term Option Series'' means a series in an option class that is approved for listing and trading on the Exchange in which the series is opened for trading on any Monday, Tuesday, Wednesday, Thursday or Friday that is a business day and that expires on the Monday, Wednesday or Friday of the next business week, or, in the case of a series that is listed on a Friday and expires on a Monday, is listed one business week and one business day prior to that expiration. If a Tuesday, Wednesday, Thursday or Friday is not a business day, the series may be opened (or shall expire) on the first business day immediately prior to that Tuesday, Wednesday, Thursday or Friday, respectively. For a series listed pursuant to this section for Monday expiration, if a Monday is not a business day, the series shall expire on the first business day immediately following that Monday.

ISE's Options 4 rules were recently amended to expand the Short Term Option Series program to permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program.[4] In conjunction with that change, ISE amended its definition of Short Term Option Series, within Options 1, Section 1(a)(49), to accommodate the listing of options series that expire on Tuesdays and Thursdays.[5] Specifically, the Exchange added Tuesday and Thursday to the permitted expiration days, which currently include Monday, Wednesday, and Friday, that it may open for trading.

At this time, the Exchange proposes to amend the term ''Short Term Option Series'' at Options 1, Section 1(a)(57) to provide,

The term ''Short Term Option Series'' means a series in an option class that is approved for listing and trading on the Exchange in which the series is opened for trading on any Monday, Tuesday, Wednesday, Thursday or Friday that is a business day and that expires on the Monday, Tuesday, Wednesday, Thursday, or Friday of the next business week, or, in the case of a series that is listed on a Friday and expires on a Monday, is listed one business week and one business day prior to that expiration. If a Tuesday, Wednesday, Thursday or Friday is not a business day, the series may be opened (or shall expire) on the first business day immediately prior to that Tuesday, Wednesday, Thursday or Friday, respectively. For a series listed pursuant to this section for Monday expiration, if a Monday is not a business day, the series shall expire on the first business day immediately following that Monday.

Today, NOM's listing rules permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 96281 (November 9, 2022), 87 FR 68769 (November 16, 2022) (SR–ISE–2022–18) (Order Granting Approval of a Proposed Rule Change to Amend the Short Term Option Series Program).

[4] *See* note 3 above. NOM's Options 4 Rules are incorporated by reference to ISE's Options 4 Rules.

[5] *See* note 3 above.

pursuant to the Short Term Option Series Program.[6]

Options 4A, Section 12

In 2014, NOM amended the Short Term Option Series Program for equity options within Chapter IV, Section 6 (currently Options 4, Section 5) to change the number of currently listed option classes on which Short Term Option Series may be opened on any Short Term Option Opening Date from thirty to fifty options classes.[7] Further, NOM also amended the number of Short Term Option Series that the Exchange may open for each expiration date in that class from twenty to thirty.[8] At that time, the Exchange neglected to update the index options rules to make similar changes to the Short Term Option Series Program given that the amount of options classes that may participate in the Short Term Option Series Program is aggregated between equity options and index options and is not apportioned between equity and index options.

Today, Options 4A, Section 12(h)(1)(A) provides,

> The Exchange may select up to thirty (30) currently listed option classes on which Short Term Option Series may be opened on any Short Term Option Opening Date. In addition to the 30 option class restriction, the Exchange may also list Short Term Option Series on any option classes that are selected by other securities exchanges that employ a similar program under their respective rules. For each index option class eligible for participation in the Short Term Option Series Program, the Exchange may open up to 30 Short Term Option Series on index options for each expiration date in that class. The Exchange may also open Short Term Option Series that are opened by other securities exchanges in option classes selected by such exchanges under their respective short term option rules.

At this time, the Exchange proposes to amend Options 4A, Section 12(h)(1)(A) to increase the number of currently listed options classes on which Short Term Option Series may be opened on any Short Term Option Opening Date from thirty to fifty options classes for index options. Additionally, the Exchange proposes to amend the number of Short Term Option Series the Exchange may open on index options for each expiration date in that class from twenty to thirty. These amendments would align the limitations within Options 4A, Section 12(h)(1)(A) with those currently within Supplementary .03 to Options 4, Section 5. The Exchange also proposes to add certain titles before Options 4A, Section 12(h)(1)(A)–(E) to indicate the subject matter of the paragraphs. Those non-substantive amendments are intended to bring clarity to the rule text.

As noted above, this amendment will not result in a greater number of listings in the Short Term Option Series Program because the amount of options classes that may participate in the Short Term Option Series Program is aggregated between equity options and index options and is not apportioned between equity and index options. Amending Options 4A, Section 12(h)(1)(A) to conform to the limitations provided within Supplementary .03 to Options 4, Section 5 will avoid confusion by making clear the aggregate limitations within equity and index options for listing Short Term Option Series. Today, ISE, Nasdaq Phlx LLC (''Phlx'') and Cboe Exchange, Inc. (''Cboe'') have similar limitations within their equity and index Short Term Option Series Program.[9]

Other Non-Substantive Amendments

The Exchange proposes to make other amendments to reserve certain sections of the Rulebook. These sections contain content in other Nasdaq affiliated rulebooks. To harmonize the section numbers across the Nasdaq affiliated markets, the Exchange proposes to reserve General 2, Sections 23 and 24 as well as Options 10, Sections 26 and 27. These amendments are non-substantive.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act,[10] in general, and furthers the objectives of Section 6(b)(5) of the Act,[11] in particular, in that it is designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general to protect investors and the public interest.

Short Term Option Series

The Exchange's proposal to amend the term ''Short Term Option Series'' at Options 1, Section 1(a)(57) to reflect the recent change[12] to NOM's listing rules to permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program is consistent with the Exchange Act. This proposal will align the description of Short Term Option Series within Options 1, Section 1(a)(57) to the expirations permitted within the Short Term Option Series Program within Supplementary .03 to Options 4, Section 5.

Options 4A, Section 12

In 2014, NOM amended the Short Term Option Series Program for equity options within Chapter IV, Section 6 (currently Options 4, Section 5) to change the number of currently listed option classes on which Short Term Option Series may be opened on any Short Term Option Opening Date from thirty to fifty options classes.[13] Further, NOM also amended the number of Short Term Option Series that the Exchange may open for each expiration date in that class from twenty to thirty.[14] At that time, the Exchange neglected to update the index options rules to make similar changes to the Short Term Option Series Program given that the amount of options classes that may participate in the Short Term Option Series Program is aggregated between equity options and index options and is not apportioned between equity and index options. Amending Options 4A, Section 12(h)(1)(A) to conform to the limitations provided within Supplementary .03 to Options 4, Section 5 will avoid confusion by making clear the aggregate limitations within equity and index options for listing Short Term Option Series. Also, aligning the limitations within Options 4A, Section 12(h)(1)(A) with those currently within Supplementary .03 to Options 4, Section 5 will not result in a greater number of listings in the Short Term Option Series Program because the amount of options classes that may participate in the Short Term Option Series Program is aggregated between equity options and index options and is not apportioned between equity and index options. Today, ISE, Phlx and Cboe have similar limitations within their equity and

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[6] NOM's Options 4 Rules are incorporated by reference to ISE's Options 4 Rules and therefore the approval of ISE's Options 4 rules permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ on NOM.

[7] *See* Securities Exchange Act Release Nos. 72699 (July 29, 2014), 79 FR 45506 (August 5, 2014) (SR–NASDAQ–2014–074) (Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to Short Term Option Series).

[8] *Id.*

[9] *See* ISE and Phlx Options 4A, Section 12(b)(4) and Cboe Exchange, Inc. Rules 4.5 and 4.13. *See also* Securities Exchange Act Release No. 95077 (June 9, 2022), 87 FR 36188 (June 15, 2022) (Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend Options 4A, Section 12, Terms of Index Options Contracts).

[10] 15 U.S.C. 78f(b).

[11] 15 U.S.C. 78f(b)(5).

[12] *See* note 3 above.

[13] *See* note 6 above.

[14] *See* note 6 above.

index Short Term Option Series Program.[15]

Other Non-Substantive Amendments

The Exchange's proposal to make other amendments to reserve certain sections of the Rulebook, namely General 2, Sections 23 and 24 as well as Options 10, Sections 26 and 27, to harmonize section numbers across the Nasdaq affiliated markets are non-substantive.

B. Self-Regulatory Organization's Statement on Burden on Competition

The proposed rule change does not impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

Short Term Option Series

The Exchange's proposal to amend the term ''Short Term Option Series'' at Options 1, Section 1(a)(57) to reflect the recent change [16] to NOM's listing rules to permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program does not impose an undue burden on competition, rather this proposal will align the description of Short Term Option Series within Options 1, Section 1(a)(57) to the expirations permitted within the Short Term Option Series Program within Supplementary .03 to Options 4, Section 5.

Options 4A, Section 12

Amending Options 4A, Section 12(h)(1)(A) to conform to the limitations provided within Supplementary .03 to Options 4, Section 5 will avoid confusion by making clear the aggregate limitations within equity and index options for listing Short Term Option Series. Also, aligning the limitations within Options 4A, Section 12(h)(1)(A) with those currently within Supplementary .03 to Options 4, Section 5 will not result in a greater number of listings in the Short Term Option Series Program because the amount of options classes that may participate in the Short Term Option Series Program is aggregated between equity options and index options and is not apportioned between equity and index options. Today, ISE, Phlx and Cboe has similar limitations within its equity and index Short Term Option Series Program.[17]

Other Non-Substantive Amendments

The Exchange's proposal to make other amendments to reserve certain sections of the Rulebook, namely General 2, Sections 23 and 24 as well as Options 10, Sections 26 and 27, to harmonize section numbers across the Nasdaq affiliated markets are non-substantive.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The Exchange has filed the proposed rule change pursuant to Section 19(b)(3)(A)(iii) of the Act [18] and Rule 19b–4(f)(6) thereunder.[19] Because the foregoing proposed rule change does not: (i) significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A)(iii) of the Act [20] and subparagraph (f)(6) of Rule 19b–4 thereunder.[21] The Exchange has stated that the Options 4 listing rules were recently amended to expand the Short Term Option Series program to permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program,[22] and that waiver of the 30-day operative delay will allow the Exchange to conform the definition of a Short Term Option Series to the Options 4 listing rules. The Commission believes that waiver of the 30-day operative delay is consistent with the protection of investors and the public interest because the proposed rule change does not raise any new or novel issues. Accordingly, the Commission hereby waives the operative delay and designates the proposed rule change operative upon filing.[23]

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. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or disapproved.

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–NASDAQ–2022–066 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–NASDAQ–2022–066. 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 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 office of the Exchange. All comments

[15] *See* note 8 above.

[16] *See* note 3 above.

[17] *See* note 8 above.

[18] 15 U.S.C. 78s(b)(3)(A)(iii).

[19] 17 CFR 240.19b–4(f)(6).

[20] 15 U.S.C. 78s(b)(3)(A)(iii).

[21] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6)(iii) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change, along with a brief description and text of the proposed rule change, at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

[22] *See supra* note 4.

[23] For purposes only of waiving the 30-day operative delay, the Commission has also considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

received will be posted without change. Persons submitting comments are cautioned that we do not redact or edit personal identifying information from comment submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NASDAQ–2022–066, and should be submitted on or before December 27, 2022.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[24]

Sherry R. Haywood,

Assistant Secretary.

[FR Doc. 2022–26442 Filed 12–5–22; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–96411; File No. SR–Phlx–2022–38]

Self-Regulatory Organizations; Nasdaq PHLX LLC; Order Granting Approval of a Proposed Rule Change To Permit the Listing and Trading of P.M.-Settled Nasdaq 100 Micro Index Options That Expire on Tuesday or Thursday Under Its Nonstandard Expirations Pilot Program

November 30, 2022.

I. Introduction

On October 4, 2022, Nasdaq PHLX LLC (''Phlx'' or the Exchange'') filed with the Securities and Exchange Commission (''Commission''), pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1] and Rule 19b–4 thereunder,[2] a proposed rule change to expand the Exchange's Nonstandard Expirations Pilot Program (''Pilot Program'') to permit the listing and trading of P.M.-settled Nasdaq 100 Micro Index Options (''XND'') that expire on Tuesday or Thursday. The proposed rule change was published for comment in the **Federal Register** on October 21, 2022.[3] No comments were received. The Commission is approving the proposed rule change.

II. Description of the Proposal

The Exchange proposes to expand the Pilot Program by amending Options 4A, Section 12(b)(5) to permit the listing and trading of XND options that expire on any Tuesday or Thursday. The Pilot Program permits the listing and trading of P.M.-settled options on broad-based indexes with nonstandard expirations dates.[4] Under the Pilot Program, the Exchange may open for trading P.M.-settled options on broad-based indexes that expire on: (1) any Monday, Wednesday, or Friday and, with respect to options on the Nasdaq–100 Index (''NDX''),[5] any Tuesday or Thursday (''Weekly Expirations'')[6] and (2) the last trading day of the month (''EOMs'').[7] The Exchange notes that permitting XND options with Tuesday and Thursday expirations, as proposed, would be in addition to the XND options with Monday, Wednesday and Friday expirations that the Exchange currently lists, as they are permissible Weekly Expirations for options on a broad-based index pursuant to Options 4A, Section 12(b)(5)(A).[8]

The Exchange states that the Pilot Program will apply to XND options with Tuesday and Thursday expirations in the same manner as it currently applies to all other P.M.-settled broad-based index options with Monday, Wednesday, and Friday expirations and to Nasdaq–100 Index options with Tuesday and Thursday expirations.[9] Options with Tuesday and Thursday expirations, including the proposed XND Tuesday and Thursday expirations, would be subject to all provisions within Options 4A, Section 12(b)(5) and treated the same as options on the same underlying index that expire on the third Friday of the expiration month; provided, however, that Weekly Expirations are P.M.-settled, and new series in Weekly Expirations may be added up to and including on the expiration date for an expiring Weekly Expiration.[10]

The Exchange states that the maximum number of XND options expirations that may be listed for each Weekly Expiration (*i.e.,* a Monday expiration, Tuesday expiration, Wednesday expiration, Thursday expiration, or Friday expiration, as applicable) in a given class would be the same as the maximum number of expirations permitted in Options 4A, Section 12(a)(4)[11] for standard options on the same broad-based index.[12]

Weekly Expirations need not be for consecutive Monday, Tuesday, Wednesday, Thursday, or Friday expirations as applicable; however, the expiration date of a non-consecutive expiration may not be beyond what would be considered the last expiration date if the maximum number of expirations were listed consecutively. Weekly Expirations that are initially listed in a given class may expire up to four weeks from the actual listing date. If the Exchange lists EOMs and Weekly Expirations as applicable in a given class, the Exchange will list an EOM instead of a Weekly Expiration that expires on the same day in the given class. Other expirations in the same class are not counted as part of the maximum number of Weekly Expirations for an applicable broad-based index class.[13]

If the Exchange is not open for business on a respective Monday, the normally Monday expiring Weekly Expirations will expire on the following business day.[14] If the Exchange is not open for business on a respective Tuesday, Wednesday, Thursday, or Friday, the normally Tuesday, Wednesday, Thursday, or Friday expiring Weekly Expirations will expire on the previous business day.[15] The proposed rule change also adds that if two different Weekly Expirations on XND options would expire on the same day because the Exchange is not open for business on a certain weekday, the Exchange will list only one of such Weekly Expirations. Transactions in Weekly Expirations may be effected on the Exchange between the hours of 9:30 a.m. (Eastern Time) and 4:15 p.m. (Eastern Time), except that that on the last trading day, transactions in expiring P.M.-settled broad-based index options may be effected on the Exchange

[24] 17 CFR 200.30–3(a)(12), (59).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 96090 (October 17, 2022), 87 FR 64119 (''Notice'').

[4] *See* Securities Exchange Act Release No. 82341 (December 15, 2017), 82 FR 60651 (December 21, 2017) (approving SR–Phlx–2017–79) (Order Approving a Proposed Rule Change, as Modified by Amendment No. 1 and Granting Accelerated Approval of Amendment No. 2, of a Proposed Rule Change To Establish a Nonstandard Expirations Pilot Program) (''Pilot Program Approval Order'').

[5] XND options trade independently of and in addition to NDX options, and the XND options are subject to the same rules that presently govern the trading of index options based on the Nasdaq–100 Index, including sales practice rules, margin requirements, trading rules, and position and exercise limits. *See* Notice, *supra* note 3, at 64119.

[6] *See* Options 4A, Section 12(b)(5)(A).

[7] *See* Options 4A, Section 12(b)(5)(B).

[8] *See* Notice, *supra* note 3, at 64119.

[9] *See id.*

[10] *See* Notice, *supra* note 3, at 64119–64120.

[11] Options 4A, Section 12(a)(4) provides, ''Index options contracts may expire at three (3)-month intervals or in consecutive weeks or months. The Exchange may list: (i) up to six (6) standard monthly expirations at any one time in a class, but will not list index options that expire more than twelve (12) months out; (ii) up to 12 standard monthly expirations at any one time for any class that the Exchange (as the Reporting Authority) uses to calculate a volatility index; and (iii) up to 12 standard (monthly) expirations in NDX options and XND options.''

[12] *See* Notice, *supra* note 3, at 64120.

[13] *See id.*

[14] *See id.*

[15] *See id.*

between the hours of 9:30 a.m. (Eastern time) and 4:00 p.m. (Eastern time).[16]

Pilot Report

The Exchange states that it intends to submit a rule change proposing permanency of the Pilot Program to the Commission and would include data regarding XND options that expire on Tuesdays or Thursdays as it does for current Weekly Expirations on any broad-based index option either by providing additional data in such proposal or in an annual report regarding XND options that expire on each trading day of the week, as proposed.[17] The Exchange would also continue to provide the Commission with ongoing data regarding XND options that expire on Tuesdays or Thursdays unless and until the Pilot Program is made permanent or discontinued.[18]

As provided in the Pilot Program Approval Order,[19] the annual report will contain an analysis of volume, open interest and trading patterns. In addition, for series that exceed certain minimum open interest parameters, the annual report will provide analysis of index price volatility and, if needed, share trading activity.[20] Additionally, the Exchange will provide the Commission with any additional data or analyses the Commission requests because it deems such data or analyses necessary to determine whether the Pilot Program, including XND options with Tuesday and Thursday expirations as proposed, is consistent with the Act.[21] As it does for current Pilot Program products, the Exchange will make public on its website all data and analyses in connection with XND options with Tuesday and Thursday expirations it submits to the Commission under the Pilot Program.[22] Going forward, the Exchange will include the same areas of analysis for XND options with Tuesday and Thursday expirations. The Exchange also proposes to include the following market quality data, over sample periods determined by the Exchange and the Commission, for XND options (XND and standard NDX options) as part of the annual reports going forward: (1) time-weighted relative quoted spreads; (2) relative effective spreads; and (3) time-weighted bid and offer sizes.[23]

III. Discussion and Commission Findings

After careful review, the Commission finds that the proposed rule change is consistent with the requirements of the Act and the rules and regulations thereunder applicable to a national securities exchange and, in particular, with section 6(b) of the Act.[24] In particular, the Commission finds that the proposed rule change is consistent with section 6(b)(5) of the Act,[25] which requires, among other things, that a national securities exchange have rules designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitating transactions in securities, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general, to protect investors and the public interest.

As the Commission noted in its recent order approving the listing and trading of P.M.-settled options on the S&P 500 Index that expire on Tuesday or Thursday, the Commission has had concerns about the potential adverse effects and impact of P.M. settlement upon market volatility and the operation of fair and orderly markets on the underlying cash markets at or near the close of trading, including for cash-settled derivatives contracts based on a broad-based index.[26] The potential impact today remains unclear, given the significant changes in the closing procedures of the primary markets in recent decades. The Commission is mindful of the historical experience with the impact of P.M. settlement of cash-settled index derivatives on the underlying cash markets, but recognizes that these risks may be mitigated today by the enhanced closing procedures that are now in use at the primary equity markets.

The Exchange's proposal to add Tuesday and Thursday XND expirations to the existing Pilot Program would offer additional investment options to investors and may be useful for their investment or hedging objectives while providing the Commission with data to monitor the effects of Tuesday and Thursday XND expirations and the impact of P.M. settlement on the markets. To assist the Commission in assessing any potential impact of Tuesday and Thursday XND expirations on the options markets as well as the underlying cash equities markets, the Exchange will be required to submit data to the Commission in connection with the Pilot Program.[27] Further, including the proposed Tuesday and Thursday XND expirations in the Pilot Program, together with the data and analysis that the Exchange will provide to the Commission, will allow the Exchange and the Commission to monitor for and assess any potential for adverse market effects of allowing Tuesday and Thursday XND expirations, including on the underlying component stocks. In particular, the data collected from the Pilot Program will help inform the Commission's consideration of whether the Pilot Program, as amended to include Tuesday and Thursday XND expirations, should be modified, discontinued, extended, or permanently approved. Furthermore, the Exchange's ongoing analysis of the Pilot Program should help it monitor any potential risks from large P.M.-settled positions and take appropriate action if warranted.

For the foregoing reasons, the Commission finds that the proposed rule change is consistent with the Act.

IV. Conclusion

It is therefore ordered, pursuant to section 19(b)(2) of the Act,[28] that the proposed rule change (SR–Phlx–2022–38), be, and hereby is, approved.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[29]

Sherry R. Haywood,

Assistant Secretary.

[FR Doc. 2022–26441 Filed 12–5–22; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[SEC File No. 270–629, OMB Control No. 3235–0718]

Proposed Collection; Comment Request; Extension: Regulation SBSR

Upon Written Request, Copies Available From: Securities and Exchange

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[16] *See id.; see also,* Options 4A, Section 12(b)(5)(D).

[17] *See* Notice, *supra* note 3, at 64120.

[18] *See id.*

[19] *See supra* note 5.

[20] *See* Notice, *supra* note 3, at 64120.

[21] *See id.*

[22] *See* Notice, *supra* note 3, at 64120–64121.

[23] *See* Notice, *supra* note 3, at 64121.

[24] 15 U.S.C. 78f(b). In approving this proposed rule change, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[25] 15 U.S.C. 78f(b)(5).

[26] *See* Securities Exchange Act Release No. 94682 (April 12, 2022), 87 FR 22993 (April 18, 2022) (CBOE–2022–005).

[27] *See* Notice, *supra* note 3, at 64120–64121.

[28] 15 U.S.C. 78s(b)(2).

[29] 17 CFR 200.30–3(a)(12).

Commission, Office of FOIA Services, 100 F Street NE, Washington, DC 20549–2736

Notice is hereby given that pursuant to the Paperwork Reduction Act of 1995 (''PRA'') (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (''Commission'') is soliciting comments on the existing collection of information provided for in Rules 901, 902, 903(a), 904, 905, 906, 907, and 908 of Regulation SBSR (17 CFR 242.901, 902, 903(a), 904, 905, 906, 907, and 908), under the Securities Exchange Act of 1934 (15 U.S.C. 78a *et seq.*). The Commission plans to submit this existing collection of information to the Office of Management and Budget (''OMB'') for extension and approval.

Regulation SBSR consists of ten rules, Rules 900 to 909 under the Exchange Act. Regulation SBSR provides generally for the reporting of security-based swap information to a registered security-based swap data repository (''registered SDRs'') or to the Commission, and for the public dissemination of security-based swap transaction, volume, and pricing information by registered SDRs. Rule 901 specifies, with respect to each reportable event pertaining to covered transactions, who is required to report, what data must be reported, when it must be reported, where it must be reported, and how it must be reported. Rule 901(a)(1) of Regulation SBSR requires a platform to report to a registered SDR a security-based swap executed on such platform that will be submitted to clearing. Rule 901(a)(2)(i) of Regulation SBSR requires a registered clearing agency to report to a registered SDR any security-based swap to which it is a counterparty. Rules 902 to 909 of Regulation SBSR provide additional details as to how such reporting and public dissemination is to occur.

The Commission estimates that a total of approximately 30,348 entities will be impacted by Regulation SBSR, including registered SDRs, registered security-based swap dealers, registered major securities-based swap participants, registered clearing agencies, platforms, and reporting sides and other market participants. The Commission estimates that the total annual hour burden for Regulation SBSR, for all respondents, is approximately 3,539,483 hours per year. In addition, the Commission estimates that the total annual cost burden for Regulation SBSR for all respondents is approximately $47,728,783 per year. A detailed break-down of the burdens applicable to each type of entity is provided in the supporting statement.

Written comments are invited on: (a) 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; (b) the accuracy of the Commission's estimates of the burden of the proposed collection of information; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology. Consideration will be given to comments and suggestions submitted in writing by February 6, 2023.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information under the PRA unless it displays a currently valid OMB control number.

Please direct your written comments to: David Bottom, Director/Chief Information Officer, Securities and Exchange Commission, c/o John Pezzullo, 100 F Street NE, Washington, DC 20549, or send an email to: *PRA_Mailbox@sec.gov.*

Dated: November 30, 2022.

Sherry R. Haywood,

Assistant Secretary.

[FR Doc. 2022–26425 Filed 12–5–22; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[SEC File No. 270–448, OMB Control No. 3235–0507]

Proposed Collection; Comment Request; Extension: Rule 19b–5 and Form PILOT

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of FOIA Services, 100 F Street NE, Washington, DC 20549–2736

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (''PRA'') (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (''SEC'') is soliciting comments on the existing collection of information provided for in Rule 19b–5 (17 CFR 240.19b–5) and Form PILOT (17 CFR 249.821) under the Securities Exchange Act of 1934 (''Exchange Act'') (15 U.S.C. 78a *et seq.*). The SEC plans to submit this existing collection of information to the Office of Management and Budget (''OMB'') for extension and approval.

Rule 19b–5 provides a temporary exemption from the rule-filing requirements of section 19(b) of the Exchange Act (15 U.S.C. 78s(b)) to self-regulatory organizations (''SROs'') wishing to establish and operate pilot trading systems. Rule 19b–5 permits an SRO to develop a pilot trading system and to begin operation of such system shortly after submitting an initial report on Form PILOT to the SEC. During operation of any such pilot trading system, the SRO must submit quarterly reports of the system's operation to the SEC, as well as timely amendments describing any material changes to the system. Within two years of operating such pilot trading system under the exemption afforded by Rule 19b–5, the SRO must submit a rule filing pursuant to Section 19(b)(2) of the Exchange Act (15 U.S.C. 78s(b)(2)) to obtain permanent approval of the pilot trading system from the SEC.

The collection of information is designed to allow the SEC to maintain an accurate record of all new pilot trading systems operated by SROs and to determine whether an SRO has properly availed itself of the exemption afforded by Rule 19b–5, is operating a pilot trading system in compliance with the Exchange Act, and is carrying out its statutory oversight obligations under the Exchange Act.

The respondents to the collection of information are national securities exchanges and national securities associations.

There are 24 SROs which could avail themselves of the exemption under Rule 19b–5 and the use of Form PILOT. The SEC estimates that approximately one of these SROs each year will file on Form PILOT one initial report (*i.e.,* 1 report total, for an estimated annual burden of 24 hours total), four quarterly reports (*i.e.,* 4 reports total, for an estimated annual burden of 12 hours total (3 hours per report)), and two amendments (*i.e.,* 2 reports total, for an estimated annual burden of 6 hours total (3 hours per report)). Thus, the estimated annual time burden resulting from Form PILOT is 42 hours for the estimated sole SRO respondent. The SEC estimates that the aggregate annual internal cost of compliance for the sole SRO respondent is approximately $12,880 (42 hours at an average of $306.67 per hour). In addition, the SEC estimates that the sole SRO respondent will incur, in the aggregate, printing, supplies, copying, and postage expenses of $2,287 per year for filing initial reports, $1,142 per year for filing quarterly reports, and $571 per year for filing notices of material systems changes, for a total annual cost burden of $4,000.

Written comments are invited on (a) whether the proposed collection of information is necessary for the proper performance of the functions of the SEC, including whether the information shall have practical utility; (b) the accuracy of the SEC's estimate of the burden of the proposed collection of information; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

Consideration will be given to comments and suggestions submitted by February 6, 2023.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information under the PRA unless it displays a currently valid OMB control number.

Please direct your written comments to: David Bottom, Director/Chief Information Officer, Securities and Exchange Commission, c/o John Pezzullo, 100 F Street NE, Washington, DC 20549, or send an email to: *PRA_Mailbox@sec.gov.*

Dated: November 30, 2022.

Sherry R. Haywood,

Assistant Secretary.

[FR Doc. 2022–26424 Filed 12–5–22; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–96414; File No. SR–MEMX–2022–31]

Self-Regulatory Organizations; MEMX LLC; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change To Amend the Exchange's Fee Schedule

November 30, 2022.

Pursuant to section 19(b)(1) of the Securities Exchange Act of 1934 (the ''Act''),[1] and Rule 19b–4 thereunder,[2] notice is hereby given that on November 17, 2022, MEMX LLC (''MEMX'' or the ''Exchange'') filed with the Securities and Exchange Commission (the ''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.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange is filing with the Commission a proposed rule change to amend the Exchange's fee schedule applicable to Members[3] (the ''Fee Schedule'') pursuant to Exchange Rules 15.1(a) and (c). The Exchange proposes to implement the changes to the Fee Schedule pursuant to this proposal on November 17, 2022. The text of the proposed rule change is provided in Exhibit 5.

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 Exchange 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 these 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 aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposed rule change is to amend the Fee Schedule to exclude any day with a scheduled early market close from the volume calculations used by the Exchange for purposes of determining a Member's qualification for the Exchange's transaction pricing tiers. Specifically, the Exchange proposes to exclude any day with a scheduled early market close from its calculations of ADAV,[4] ADV[5] and TCV,[6] and for purposes of determining qualification for the Displayed Liquidity Incentive.

Currently, the Exchange's Fee Schedule provides that the Exchange excludes from its calculations of ADAV, ADV and TCV, and for purposes of determining qualification for the Displayed Liquidity Incentive: (1) any trading day that the Exchange's system experiences a disruption that lasts for more than 60 minutes during regular trading hours; (2) the day that Russell Investments reconstitutes its family of indexes (*i.e.,* the last Friday in June); (3) any day that the MSCI Equities Indexes are rebalanced (*i.e.,* on a quarterly basis); and (4) any day that the S&P 400, S&P 500, and S&P 600 Indexes are rebalanced (*i.e.,* on a quarterly basis).

The Exchange excludes these days from such calculations in order to avoid penalizing Members that might otherwise qualify for certain tiered pricing but that, because of special circumstances on a particular day, did not participate on the Exchange to the extent that they might have otherwise participated. Similarly, the Exchange believes that scheduled early market closes, which typically are the day before or after a holiday, may preclude some Members from submitting orders to the Exchange at the same level as they might otherwise. The Exchange notes that it is not proposing to modify any of the existing fees or rebates or the volume thresholds at which a Member may qualify for certain fees or rebates pursuant to its tiered pricing structure. Rather, as noted above, the Exchange is proposing to modify its Fee Schedule by including in the list of days excluded from its calculations of ADAV, ADV and TCV, and for purposes of determining qualification for the Displayed Liquidity Incentive, any day with a scheduled early market close.

The Exchange believes that excluding days with a scheduled early market close from its calculations of ADAV, ADV and TCV, and for purposes of determining qualification for the Displayed Liquidity Incentive, will provide Members with increased certainty as to their monthly cost for trades executed on the Exchange. In addition, the Exchange notes that excluding days with a scheduled early market close from volume calculations for purposes of determining a Member's qualification for pricing tiers is consistent with the practice of other exchanges.[7]

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with

[3] *See* Exchange Rule 1.5(p).

[4] As set forth on the Fee Schedule, ''ADAV'' means average daily added volume calculated as the number of shares added per day, which is calculated on a monthly basis.

[5] As set forth on the Fee Schedule, ''ADV'' means average daily volume calculated as the number of shares added or removed, combined, per day, which is calculated on a monthly basis.

[6] As set forth on the Fee Schedule, ''TCV'' means total consolidated volume calculated as the volume reported by all exchanges and trade reporting facilities to a consolidated transaction reporting plan for the month for which the fees apply.

[7] *See, e.g.,* Cboe BZX Exchange, Inc. equities trading fee schedule on its public website (available at *https://markets.cboe.com/us/equities/membership/fee_schedule/bzx/*); *see also* Securities Exchange Act Release No. 72589 (July 10, 2014), 79 FR 41618 (July 16, 2014) (SR–BATS–2014–025).

the provisions of Section 6 of the Act,[8] in general, and with Sections 6(b)(4) and 6(b)(5) of the Act,[9] in particular, in that it provides for the equitable allocation of reasonable dues, fees and other charges among its Members and other persons using its facilities and is not designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

The Exchange believes the proposed change to exclude any day with a scheduled early market close from the volume calculations used by the Exchange for purposes of determining a Member's qualification for the Exchange's transaction pricing tiers is reasonable because, as described above, it will help provide Members with a greater level of certainty as to their level of rebates and costs for trading in any month where there is a scheduled early market close. The Exchange is not proposing to amend the thresholds a Member must achieve to become eligible for, or the dollar value associated with, the tiered rebates or fees. Eliminating the inclusion of any day with a scheduled early market close would, in many cases, be excluding a day that would otherwise lower a Member's ADAV and/or ADV as a percentage of the TCV, as well as negatively impact a Member's average quoting activity for purposes of the Displayed Liquidity Incentive Tiers. Thus, the Exchange believes the proposed change will make the majority of Members more likely to meet the minimum or higher tier thresholds, incentivizing Members to increase their participation on the Exchange in order to meet the next highest tier. Additionally, the Exchange believes that the proposed rule change is equitable and not unfairly discriminatory because the methodology for calculating ADAV, ADV and TCV, and for purposes of determining qualification for the Displayed Liquidity Incentive, will apply equally to all Members, in that each Member's volume and quoting activities for purposes of the Exchange's transaction pricing tiers would continue to be calculated in a uniform manner and would now exclude any day with a scheduled early market close. Further, the Exchange believes that a tiered pricing model not significantly altered by a day of atypical trading behavior, which allows Members to predictably calculate their costs associated with trading activity on the Exchange, is reasonable, fair and equitable and not unreasonably discriminatory, as it is uniform in application amongst Members and should enable such participants to operate their business without concern of unpredictable and potentially significant changes in expenses.

In addition, as noted above, the proposed exclusion of any day with a scheduled early market close from volume calculations for purposes of determining a Member's qualification for pricing tiers is consistent with the practice of other exchanges, and therefore, such proposal does not raise any new or novel issues that have not previously been considered by the Commission.[10]

For the reasons discussed above, the Exchange submits that the proposal satisfies the requirements of sections 6(b)(4) and 6(b)(5) of the Act[11] in that it provides for the equitable allocation of reasonable dues, fees and other charges among its Members and other persons using its facilities and is not designed to unfairly discriminate between customers, issuers, brokers, or dealers.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposal will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act. Rather, the Exchange believes the proposed change will help to promote intramarket competition by avoiding a penalty to Members for days when overall trading activity might be significantly lower than a typical trading day. Additionally, the Exchange believes the proposal would not impose any burden on intramarket competition that is not necessary or appropriate in furtherance of the purposes of the Act because, as described above, the proposed exclusion of any day with a scheduled early market close from the relevant calculations will apply equally to all Members and in the same manner that the Exchange currently excludes certain system disruption and index rebalance days from such calculations. The Exchange does not believe the proposal would impose any burden on intermarket competition that is not necessary or appropriate in furtherance of the purposes of the Act, as the Exchange believes the proposal is not concerned with such competitive issues, but rather relates to calculation methodologies applicable to its pricing tiers.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The Exchange neither solicited nor received comments on 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 pursuant to section 19(b)(3)(A)(ii) of the Act[12] and Rule 19b–4(f)(2)[13] 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. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule change should be approved or disapproved.

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–MEMX–2022–31 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–MEMX–2022–31. 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

[8] 15 U.S.C. 78f.

[9] 15 U.S.C. 78f(b)(4) and (5).

[10] *See supra* note 7.

[11] 15 U.S.C. 78f(b)(4) and (5).

[12] 15 U.S.C. 78s(b)(3)(A)(ii).

[13] 17 CFR 240.19b–4(f)(2).

Commission, and all written communications relating to the 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 office of the Exchange. All comments received will be posted without change. Persons submitting comments are cautioned that we do not redact or edit personal identifying information from comment submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–MEMX–2022–31 and should be submitted on or before December 27, 2022.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[14]

Sherry R. Haywood,

Assistant Secretary.

[FR Doc. 2022–26444 Filed 12–5–22; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–96410; File No. SR–MRX–2022–25]

Self-Regulatory Organizations; Nasdaq MRX, LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend the Definition of Short Term Option Series

November 30, 2022.

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 November 18, 2022, Nasdaq MRX, LLC (''MRX'' or ''Exchange'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I and II 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.

[14] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend Options 1, General Provisions. The Exchange also proposes amendments within Options 7, Pricing Schedule and General 2, Organization and Administration.

The text of the proposed rule change is available on the Exchange's website at *https://listingcenter.nasdaq.com/rulebook/mrx/rules,* 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 Exchange 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 these 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 aspects 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 description of the term ''Short Term Option Series'' within Options 1, Section 1, Definitions, to conform the term to Nasdaq ISE, LLC's (''ISE'') term of Short Term Option Series which was recently amended.[3] The Exchange also proposes certain non-substantive amendments. Each change is described below.

Short Term Option Series

Options 1, Section 1(a)(48) describes the term ''Short Term Option Series'' as follows:

> The term ''Short Term Option Series'' means a series in an option class that is approved for listing and trading on the Exchange in which the series is opened for trading on any Monday, Tuesday, Wednesday, Thursday, or Friday that is a business day and that expires on the Monday, Wednesday or Friday of the following business week that is a business day, or, in the case of a series that is listed on a Friday and expires on a Monday, is listed one business week and one business day prior to that expiration. If a Tuesday, Wednesday, Thursday or Friday is not a business day, the series may be opened (or shall expire) on the first business day immediately prior to that Tuesday, Wednesday, Thursday or Friday. For a series listed pursuant to this section for Monday expiration, if a Monday is not a business day, the series shall expire on the first business day immediately following that Monday.

[3] *See* Securities Exchange Act Release No. 96281 (November 9, 2022), 87 FR 68769 (November 16, 2022) (SR–ISE–2022–18) (Order Granting Approval of a Proposed Rule Change to Amend the Short Term Option Series Program).

ISE's Options 4 rules were recently amended to expand the Short Term Option Series program to permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program.[4] In conjunction with that change, ISE amended its definition of Short Term Option Series, within Options 1, Section 1(a)(49), to accommodate the listing of options series that expire on Tuesdays and Thursdays. Specifically, the Exchange added Tuesday and Thursday to the permitted expiration days, which currently include Monday, Wednesday, and Friday, that it may open for trading.

At this time, the Exchange proposes to amend the term ''Short Term Option Series'' at Options 1, Section 1(a)(48) to provide,

> The term ''Short Term Option Series' means a series in an option class that is approved for listing and trading on the Exchange in which the series is opened for trading on any Monday, Tuesday, Wednesday, Thursday, or Friday that is a business day and that expires on the Monday, Tuesday, Wednesday, Thursday, or Friday of the following business week that is a business day, or, in the case of a series that is listed on a Friday and expires on a Monday, is listed one business week and one business day prior to that expiration. If a Tuesday, Wednesday, Thursday or Friday is not a business day, the series may be opened (or shall expire) on the first business day immediately prior to that Tuesday, Wednesday, Thursday or Friday. For a series listed pursuant to this section for Monday expiration, if a Monday is not a business day, the series shall expire on the first business day immediately following that Monday.

Today, MRX's listing rules permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program.[5]

[4] *See* note 3 above. MRX's Options 4 Rules are incorporated by reference to ISE's Options 4 Rules.

[5] MRX's Options 4 Rules are incorporated by reference to ISE's Options 4 Rules and therefore the approval of ISE's Options 4 rules permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ on MRX.

Other Non-Substantive Amendments

The Exchange proposes to make other amendments to reserve certain sections of the Rulebook. These sections contain content in other Nasdaq affiliated rulebooks. To harmonize the section numbers across the Nasdaq affiliated markets, the Exchange proposes to reserve General 2, Sections 23 and 24. These amendments are non-substantive.

The Exchange also proposes to update the name of various market data feeds to mirror the amendments that were recently made within Options 3, Section 28.[6] Amending the names of the market data feeds within Options 7, Section 7 to align with the names within the Exchange's rules will make clear which products are being described within Options 7. These amendments are non-substantive.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act,[7] in general, and furthers the objectives of Section 6(b)(5) of the Act,[8] in particular, in that it is designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general to protect investors and the public interest.

Short Term Option Series

The Exchange's proposal to amend the term ''Short Term Option Series'' at Options 1, Section 1(a)(48) to reflect the recent change [9] to MRX's listing rules to permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program is consistent with the Exchange Act. This proposal will align the description of Short Term Option Series within Options 1, Section 1(a)(48) to the expirations permitted within the Short Term Option Series Program within Supplementary .03 to Options 4, Section 5.

Other Non-Substantive Amendments

The Exchange's proposal to reserve certain sections of the Rulebook, namely General 2, Sections 23 and 24, to harmonize section numbers across the Nasdaq affiliated markets is non-substantive. The Exchange's proposal to update the name of various market data feeds within Options 7, Section 7 to mirror the amendments that were recently made within Options 3, Section 28 [10] are non-substantive.

B. Self-Regulatory Organization's Statement on Burden on Competition

The proposed rule change does not impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act.

Short Term Option Series

The Exchange's proposal to amend the term ''Short Term Option Series'' at Options 1, Section 1(a)(48) to reflect the recent change [11] to MRX's listing rules to permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program does not impose an undue burden on competition, rather this proposal will align the description of Short Term Option Series within Options 1, Section 1(a)(48) to the expirations permitted within the Short Term Option Series Program within Supplementary .03 to Options 4, Section 5.

Other Non-Substantive Amendments

The Exchange's proposal to make other amendments to reserve certain sections of the Rulebook, namely General 2, Sections 23 and 24, to harmonize section numbers across the Nasdaq affiliated markets is non-substantive. The Exchange's proposal to update the name of various market data feeds within Options 7, Section 7 to mirror the amendments that were recently made within Options 3, Section 28 [12] are non-substantive.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were either solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The Exchange has filed the proposed rule change pursuant to section 19(b)(3)(A)(iii) of the Act [13] and Rule 19b–4(f)(6) thereunder.[14] Because the foregoing proposed rule change does not: (i) significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A)(iii) of the Act [15] and subparagraph (f)(6) of Rule 19b–4 thereunder.[16] The Exchange has stated that the Options 4 listing rules were recently amended to expand the Short Term Option Series program to permit the listing and trading of options series with Tuesday and Thursday expirations for options on SPY and QQQ listed pursuant to the Short Term Option Series Program,[17] and that waiver of the 30-day operative delay will allow the Exchange to conform the definition of a Short Term Option Series to the Options 4 listing rules. The Commission believes that waiver of the 30-day operative delay is consistent with the protection of investors and the public interest because the proposed rule change does not raise any new or novel issues. Accordingly, the Commission hereby waives the operative delay and designates the proposed rule change operative upon filing.[18]

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. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or disapproved.

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:

[6] *See* Securities and Exchange Release No. 95982 (October 4, 2022), 87 FR 61391 (October 11, 2022) (SR–MRX–2022–18) (Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend Its Rules in Connection With a Technology Migration to Enhanced Nasdaq Functionality).

[7] 15 U.S.C. 78f(b).

[8] 15 U.S.C. 78f(b)(5).

[9] *See* note 3 above.

[10] *See* note 5 above.

[11] *See* note 3 above.

[12] *See* note 5 above.

[13] 15 U.S.C. 78s(b)(3)(A)(iii).

[14] 17 CFR 240.19b–4(f)(6).

[15] 15 U.S.C. 78s(b)(3)(A)(iii).

[16] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6)(iii) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change, along with a brief description and text of the proposed rule change, at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

[17] *See supra* note 4.

[18] For purposes only of waiving the 30-day operative delay, the Commission has also considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

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–MRX–2022–25 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–MRX–2022–25. 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 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 office of the Exchange. All comments received will be posted without change. Persons submitting comments are cautioned that we do not redact or edit personal identifying information from comment submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–MRX–2022–25, and should be submitted on or before December 27, 2022.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[19]

Sherry R. Haywood,

Assistant Secretary.

[FR Doc. 2022–26440 Filed 12–5–22; 8:45 am]

BILLING CODE 8011–01–P

[19] 17 CFR 200.30–3(a)(12), (59).

SECURITIES AND EXCHANGE COMMISSION

[SEC File No. 270–019, OMB Control No. 3235–0012]

Proposed Collection; Comment Request; Extension: Rule 15b1–1/Form BD

Upon Written Request, Copies Available From: Securities and Exchange Commission, Office of FOIA Services, 100 F Street NE, Washington, DC 20549–2736

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (''PRA'') (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (''Commission'') is soliciting comments on the collection of information provided for in Rule 15b1–1 (17 CFR 240.15b1–1) and Form BD (17 CFR 249.501) under the Securities Exchange Act of 1934 (17 U.S.C. 78a *et seq.*). The Commission plans to submit this existing collection of information to the Office of Management and Budget (''OMB'') for extension and approval.

Form BD is the application form used by firms to apply to the Commission for registration as a broker-dealer, as required by Rule 15b1–1. Form BD also is used by firms other than banks and registered broker-dealers to apply to the Commission for registration as a municipal securities dealer or a government securities broker-dealer. In addition, Form BD is used to change information contained in a previous Form BD filing that becomes inaccurate.

The total industry-wide annual time burden imposed by Form BD is approximately 3,703 hours, based on approximately 9,842 responses (175 initial filings + 9,667 amendments). Each application filed on Form BD requires approximately 2.75 hours to complete and each amended Form BD requires approximately 20 minutes to complete. (175×2.75 hours = 481 hours; $9,667 \times 0.33333333$ hours = 3,222 hours; 481 hours + 3,222 hours = 3,703 hours.) The staff believes that a broker-dealer would have a Compliance Manager complete and file both applications and amendments on Form BD at a cost of approximately $344/hour. Consequently, the staff estimates that the total internal cost of compliance associated with the annual time burden is approximately $1,273,832 per year ($\$344 \times 3,703$).

The Commission uses the information disclosed by applicants in Form BD: (1) to determine whether the applicant meets the standards for registration set forth in the provisions of the Exchange Act; (2) to develop a central information resource where members of the public may obtain relevant, up-to-date information about broker-dealers, municipal securities dealers, and government securities broker-dealers, and where the Commission, other regulators, and SROs may obtain information for investigatory purposes in connection with securities litigation; and (3) to develop statistical information about broker-dealers, municipal securities dealers, and government securities broker-dealers. Without the information disclosed in Form BD, the Commission could not effectively implement policy objectives of the Exchange Act with respect to its investor protection function.

Completing and filing Form BD is mandatory in order to engage in broker-dealer activity. Compliance with Rule 15b1–1 does not involve the collection of confidential information.

Written comments are invited on: (a) 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; (b) the accuracy of the Commission's estimates of the burden of the proposed collection of information; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology. Consideration will be given to comments and suggestions submitted by February 6, 2023.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information under the PRA unless it displays a currently valid OMB control number.

Please direct your written comments to: David Bottom, Director/Chief Information Officer, Securities and Exchange Commission, c/o John Pezzullo, 100 F Street NE, Washington, DC 20549, or send an email to: *PRA_Mailbox@sec.gov.*

Dated: November 30, 2022.

Sherry R. Haywood,

Assistant Secretary.

[FR Doc. 2022–26426 Filed 12–5–22; 8:45 am]

BILLING CODE 8011–01–P

SMALL BUSINESS ADMINISTRATION

[Disaster Declaration # 17722; Washington Disaster Number WA–00109 Declaration of Economic Injury]

Administrative Declaration of an Economic Injury Disaster for the State of Washington

AGENCY: U.S. Small Business Administration.

ACTION: Notice.

SUMMARY: This is a notice of an Economic Injury Disaster Loan (EIDL) declaration for the State of Washington dated 11/30/2022.

Incident: Bolt Creek Wildfire.

Incident Period: 09/10/2022 through 10/21/2022.

DATES: Issued on 11/30/2022.

Economic Injury (EIDL) Loan Application Deadline Date: 08/30/2023.

ADDRESSES: Submit completed loan applications to: U.S. Small Business Administration, Processing and Disbursement Center, 14925 Kingsport Road, Fort Worth, TX 76155.

FOR FURTHER INFORMATION CONTACT: Alan Escobar, Office of Disaster Assistance, U.S. Small Business Administration, 409 3rd Street SW, Suite 6050, Washington, DC 20416, (202) 205–6734.

SUPPLEMENTARY INFORMATION: Notice is hereby given that as a result of the Administrator's EIDL declaration, applications for economic injury disaster loans may be filed at the address listed above or other locally announced locations.

The following areas have been determined to be adversely affected by the disaster:

Primary Counties:

King, Snohomish.

Contiguous Counties:

WASHINGTON

Chelan, Island, Kitsap, Kittitas, Pierce, Skagit, Yakima.

The Interest Rates are:

	Percent
Businesses and Small Agricultural Cooperatives without Credit Available Elsewhere	3.040
Non-Profit Organizations without Credit Available Elsewhere	1.875

The number assigned to this disaster for economic injury is 177220.

The States which received an EIDL Declaration #17722 are Washington.

(Catalog of Federal Domestic Assistance Number 59008)

Isabella Guzman,

Administrator.

[FR Doc. 2022–26457 Filed 12–5–22; 8:45 am]

BILLING CODE 8026–09–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Notice of Intent to Rule on Request To Release Airport Property at the Colorado Air and Space Port, Watkins, Colorado

AGENCY: Federal Aviation Administration, (FAA), DOT.

ACTION: Notice of request to release airport property.

SUMMARY: The FAA proposes to rule and invite public comment on the release and sale of a 5,457 square foot parcel of land at the Colorado Air and Space Port.

DATES: Comments are due within 30 days of the date of the publication of this notice in the **Federal Register**.

ADDRESSES: Emailed comments can be provided to Mr. Michael Matz, Project Manager/Compliance Specialist, Denver Airports District Office, *michael.b.matz@faa.gov,* (303) 342–1251.

FOR FURTHER INFORMATION CONTACT: Mr. Jeff Kloska, Director, Colorado Air and Space Port, 5200 Front Range Parkway, Watkins, CO 80137, *JKloska@adcogov.org,* (720) 523–7310; or Michael Matz, Project Manager/Compliance Specialist, Denver Airports District Office, 26805 E. 68th Ave. Suite 224, Denver, CO 80249, *michael.b.matz@faa.gov,* (303) 342–1251. Documents reflecting this FAA action may be reviewed at the above locations.

SUPPLEMENTARY INFORMATION:

The FAA invites public comment on the request to release property at the Colorado Air and Space Port under the provisions of 49 U.S.C. 47107(h)(2). The proposal consists of 5,457 square feet of land located on the North side of the airport, shown as Parcel 7B on the Airport Layout Plan. The parcel lies on the Northeast corner of East 56th Avenue and Imboden Road. The FAA concurs that the parcel is no longer needed for airport purposes. The proposed use of this property is compatible with existing airport operations in accordance with FAA's Policy and Procedures Concerning the Use of Airport Revenue, as published in the **Federal Register** on February 16, 1999.

Issued in Denver, Colorado, on November 30, 2022.

Marc Miller,

Acting Manager, Denver Airports District Office.

[FR Doc. 2022–26469 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

Notice of Final Federal Agency Actions on Proposed Highway in California; Statute of Limitations on Claims

AGENCY: Federal Highway Administration (FHWA), Department of Transportation (DOT).

ACTION: Notice of Limitation on Claims for Judicial Review of Actions by the California Department of Transportation (Caltrans).

SUMMARY: The FHWA, on behalf of Caltrans, is issuing this notice to announce Caltrans' adoption of the Maritime Administration's (MARAD) Combined Final Environmental Impact Statement/Record of Decision and Final Section 4(f) Evaluation, (FEIS/ROD) for the Port of Long Beach (POLB or Port) Pier B On-Dock Rail Support Facility Project (Project).

The Final EIS and ROD for the Pier B On-Dock Rail Support Facility Project were approved by MARAD on April 7, 2022. MARAD's Notice of Availability for the Final EIS and ROD was published in the **Federal Register** on April 15, 2022. Under 49 U.S.C. 304a(b), MARAD issued a single Final EIS and ROD (USEPA, 2022). Therefore, the 30-day wait/review period under the National Environmental Policy Act (NEPA) did not apply to the action (**Federal Register**, 2022).

Pursuant to 40 CFR 1506.3(b)(2), Caltrans was a cooperating agency on this project. Therefore, recirculation of the document is not necessary under Section 1506.3(c) of the Council on Environmental Quality (CEQ) regulations.

DATES: By this notice, the FHWA, on behalf of Caltrans, is advising the public of final agency actions subject to 23 U.S.C. 139(l)(1). A claim seeking judicial review of the Federal agency actions on the highway project will be barred unless the claim is filed on or before May 5, 2023. If the Federal law that authorizes judicial review of a claim provides a time period of less than 150 days for filing such claim, then that shorter time period still applies.

FOR FURTHER INFORMATION CONTACT: For Caltrans: For Caltrans District 7:

Michael Enwedo, Branch Chief, Division of Environmental Planning, California Department of Transportation-District 7, 100 S Main Street, Los Angeles, CA 90012. Office Hours: 8 a.m.–5 p.m., Pacific Standard Time, Telephone: (213) 335–0060 or Email: *michael.enwedo@dot.ca.gov*.

SUPPLEMENTARY INFORMATION: Subsequent to MARAD's ROD issued for the entire Pier B On-Dock Rail Support Facility Project, pursuant to 40 Code of Federal Regulations (CFR) 1505.2 and 23 CFR 771.127 Caltrans issued a ROD for the Pier B Street Freight Corridor Reconstruction Project on November 9th, 2022, which is a component of the Pier B On-Dock Rail Support Facility Project. Caltrans is a cooperating agency for the Pier B On-Dock Rail Support Facility Project. This ROD is solely for Caltrans approval of the Pier B Street Freight Corridor Reconstruction Project.

The Pier B Street Freight Corridor Reconstruction Project scope includes the following:

- *Pier B Street:* Realignment of Pier B St between Pico Av and Anaheim St and widening into two lanes in each direction to improve goods movement mobility and enhance pedestrian travel. The realignment of Pier B Street would require the reconstruction of two intersections, at Anaheim Way and Edison Avenue.
- *9th Street Crossing:* The existing at-grade 9th Street railroad grade crossing would be closed. After the intersection with 9th street is closed, access to Interstate (I–) 710 would remain open at Pico Avenue, where the existing ramp at the 9th Street/Pico Avenue intersection is located. Access to Anaheim Street would be shifted to Anaheim Way and Farragut Avenue at the western end of Pier B Street.
- *Removal of Shoemaker Ramps:* The Shoemaker ramps and approaches would be removed. The Shoemaker north approach and the 9th Street bridge north approach would be demolished.
- *Pico Avenue:* Pico Avenue is located within a narrow corridor 1 between I–710 and several buildings, terminals, and ramps. Pico Avenue would be realigned to the west from Pier B St/I–710 ramps south to approximately Pier D Street to accommodate the addition of our railroad tracks. The existing at-grade crossing at Pico Avenue/Pier D Street would be closed.
- *Sidewalk:* Construction of new sidewalk on the south side of Pier B St and along the west 7 side of Pico Ave.

(Catalog of Federal Domestic Assistance Program Number 20.205, Highway Planning and Construction. The regulations implementing Executive Order 12372 regarding intergovernmental consultation on Federal programs and activities apply to this program.)

Authority: 23 U.S.C. 139(l)(1).

Antonio Johnson,

Director, Planning, Environment and Right of Way, Federal Highway Administration, California Division.

[FR Doc. 2022–26495 Filed 12–5–22; 8:45 am]

BILLING CODE 4910–RY–P

UNIFIED CARRIER REGISTRATION PLAN

Sunshine Act Meetings

TIME AND DATE: December 8, 2022, 9:30 a.m. to 12:00 p.m., Eastern time.

PLACE: This meeting will take place at the Holiday Inn, Savannah, Historic District, 520 West Bryan Street, Savannah, GA 31401. The meeting will also be accessible via conference call and via Zoom Meeting and Screenshare. Any interested person may call (i) 1–929–205–6099 (US Toll) or 1–669–900–6833 (US Toll) or (ii) 1–877–853–5247 (US Toll Free) or 1–888–788–0099 (US Toll Free), Meeting ID: 925 0137 8101, to listen and participate in this meeting. The website to participate via Zoom Meeting and Screenshare is *https://kellen.zoom.us/meeting/register/tJYod-irqTMrGtWn3MER5rpCqdX9CTXj791m*.

STATUS: This meeting will be open to the public.

MATTERS TO BE CONSIDERED: The Unified Carrier Registration Plan Education and Training Subcommittee (the ''Subcommittee'') will continue its work in developing and implementing the Unified Carrier Registration Plan and Agreement. The subject matter of this meeting will include:

Proposed Agenda

I. Call to Order—UCR Education and Training Subcommittee Chair

The Subcommittee Chair will welcome attendees, call the meeting to order, call roll for the Subcommittee, confirm whether a quorum is present, and facilitate self-introductions.

II. Verification of Publication of Meeting Notice—UCR Executive Director

The UCR Executive Director will verify the publication of the meeting notice on the UCR website and distribution to the UCR contact list via email followed by the subsequent publication of the notice in the **Federal Register**.

III. Review and Approval of Subcommittee Agenda and Setting of Ground Rules—UCR Education and Training Subcommittee Chair

For Discussion and Possible Subcommittee Action

The Subcommittee Agenda will be reviewed, and the Subcommittee will consider adoption.

Ground Rules

Subcommittee action only to be taken in designated areas on agenda

IV. Review and Approval of Subcommittee Minutes from the September 15, 2022 Subcommittee Meeting—UCR Education and Training Subcommittee Chair

For Discussion and Possible Subcommittee Action

Draft minutes from the September 15, 2022, Subcommittee meeting via teleconference will be reviewed. The Subcommittee will consider action to approve.

V. Roadside Enforcement Module Video Update:—UCR Education and Training Subcommittee Chair

The Subcommittee Chair will provide a final update on the Roadside Enforcement Module that describes the steps a roadside law enforcement officer would use to enforce UCR.

VI. UCR Education and E-Certificate Strategy:—UCR Education and Training Subcommittee Chair

The Subcommittee Chair will discuss the UCR E-Certificate and review the assigned questions from the previous Subcommittee meeting.

VII. UCR Volunteer Training Module—UCR Chief of Staff

The Subcommittee Chair and UCR Chief of Staff will discuss the UCR Volunteer Training Module.

VIII. Other Business—UCR Education and Training Subcommittee Chair

The Subcommittee Chair will call for any other items Subcommittee members would like to discuss.

IX. Adjournment—UCR Education and Training Subcommittee Chair

The Subcommittee Chair will adjourn the meeting.

The agenda will be available no later than 5:00 p.m. Eastern time, November 30, 2022, at: *https://plan.ucr.gov*.

CONTACT PERSON FOR MORE INFORMATION: Elizabeth Leaman, Chair, Unified Carrier Registration Plan Board of

Directors, (617) 305–3783, *eleaman@board.ucr.gov.*

Alex B. Leath,

Chief Legal Officer, Unified Carrier Registration Plan.

[FR Doc. 2022–26581 Filed 12–2–22; 11:15 am]

BILLING CODE 4910–YL–P

DEPARTMENT OF VETERANS AFFAIRS

[OMB Control No. 2900–0099]

Agency Information Collection Activity: Dependent's Request for Change of Program or Place of Training

AGENCY: Veterans Benefits Administration, Department of Veterans Affairs.

ACTION: Notice.

SUMMARY: Veterans Benefits Administration, Department of Veterans Affairs (VA), is announcing an opportunity for public comment on the proposed collection of certain information by the agency. Under the Paperwork Reduction Act (PRA) of 1995, Federal agencies are required to publish notice in the **Federal Register** concerning each proposed collection of information, including each proposed revision of a currently approved collection, and allow 60 days for public comment in response to the notice.

DATES: Written comments and recommendations on the proposed collection of information should be received on or before February 6, 2023.

ADDRESSES: Submit written comments on the collection of information through Federal Docket Management System (FDMS) at *www.Regulations.gov* or to Nancy J. Kessinger, Veterans Benefits Administration (20M33), Department of Veterans Affairs, 810 Vermont Avenue NW, Washington, DC 20420 or email to *nancy.kessinger@va.gov.* Please refer to ''OMB Control No. 2900–0099'' in any correspondence. During the comment period, comments may be viewed online through FDMS.

FOR FURTHER INFORMATION CONTACT: Maribel Aponte, Office of Enterprise and Integration, Data Governance Analytics (008), 810 Vermont Ave. NW, Washington, DC 20006, (202) 266–4688 or email *maribel.aponte@va.gov.* Please refer to ''OMB Control No. 2900–0099'' in any correspondence.

SUPPLEMENTARY INFORMATION: Under the PRA of 1995, Federal agencies must obtain approval from the Office of Management and Budget (OMB) for each collection of information they conduct or sponsor. This request for comment is being made pursuant to section 3506(c)(2)(A) of the PRA.

With respect to the following collection of information, VBA invites comments on: (1) whether the proposed collection of information is necessary for the proper performance of VBA's functions, including whether the information will have practical utility; (2) the accuracy of VBA's estimate of the burden 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 through the use of automated collection techniques or the use of other forms of information technology.

Authority: 38 U.S.C. 3034(a), 3034(b), 3323(a), 3323(b), 3471, 3513, 3521, and 3691.

Title: Dependent's Request for Change of Program or Place of Training.

OMB Control Number: 2900–0099.

Type of Review: Revision of a currently approved collection.

Abstract: VA uses the information collection to determine (1) if the claimant continues to qualify for education benefits when taking a different program of training and (2) to verify that a new place of training is approved for benefits. The information on the form can be obtained only from the individual claimant. VA cannot make an eligibility determination without this information. There is a decrease in the number of burden hours due to a decrease in the average number of forms received for periods 2019, 2020 and 2021.

Affected Public: Individuals or Households.

Estimated Annual Burden: 11,358 hours.

Estimated Average Burden Time per Respondent: 15 minutes.

Frequency of Response: On Occasion.

Estimated Number of Respondents: 45,434.

By direction of the Secretary.

Dorothy Glasgow,

VA PRA Clearance Officer (Alt.), Office of Enterprise and Integration/Data Governance Analytics, Department of Veterans Affairs.

[FR Doc. 2022–26454 Filed 12–5–22; 8:45 am]

BILLING CODE 8320–01–P

DEPARTMENT OF VETERANS AFFAIRS

[OMB Control No. 2900–0465]

Agency Information Collection Activity: Student Verification of Enrollment

AGENCY: Veterans Benefits Administration, Department of Veterans Affairs.

ACTION: Notice.

SUMMARY: Veterans Benefits Administration, Department of Veterans Affairs (VA), is announcing an opportunity for public comment on the proposed collection of certain information by the agency. Under the Paperwork Reduction Act (PRA) of 1995, Federal agencies are required to publish notice in the **Federal Register** concerning each proposed collection of information, including each proposed revision of a currently approved collection, and allow 60 days for public comment in response to the notice.

DATES: Written comments and recommendations on the proposed collection of information should be received on or before February 6, 2023.

ADDRESSES: Submit written comments on the collection of information through Federal Docket Management System (FDMS) at *www.Regulations.gov* or to Nancy J. Kessinger, Veterans Benefits Administration (20M33), Department of Veterans Affairs, 810 Vermont Avenue NW, Washington, DC 20420 or email to *nancy.kessinger@va.gov.* Please refer to ''OMB Control No. 2900–0465'' in any correspondence. During the comment period, comments may be viewed online through FDMS.

FOR FURTHER INFORMATION CONTACT: Maribel Aponte, Office of Enterprise and Integration, Data Governance Analytics (008), 810 Vermont Ave. NW, Washington, DC 20006, (202) 266–4688 or email *maribel.aponte@va.gov.* Please refer to ''OMB Control No. 2900–0465'' in any correspondence.

SUPPLEMENTARY INFORMATION: Under the PRA of 1995, Federal agencies must obtain approval from the Office of Management and Budget (OMB) for each collection of information they conduct or sponsor. This request for comment is being made pursuant to Section 3506(c)(2)(A) of the PRA.

With respect to the following collection of information, VBA invites comments on: (1) whether the proposed collection of information is necessary for the proper performance of VBA's functions, including whether the information will have practical utility; (2) the accuracy of VBA's estimate of the burden 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 through the use of automated collection techniques or the use of other forms of information technology.

Authority: Section 3680(g); Public Law 96–342 Section 903; Title 10 U.S.C., National Call to Service; Chapter 31 Section 510; Title 38 U.S.C., Chapters 30, 32, 33, 35, and Title 10 U.S.C., Chapter 1606.

Title: Student Verification of Enrollment, VAF 22–8979.

OMB Control Number: 2900–0465.

Type of Review: Revision of a currently approved collection.

Abstract: The VA uses the information requested by this collection to determine the eligible beneficiaries' continued entitlement to benefits. The collection of this information is essential for the administration of these programs. The student is required to submit the verification on a monthly basis to allow for a frequent, periodic release of payment. Without this information, VA could not pay eligible beneficiaries benefits based on their proof of attendance and/or change(s) in their enrollment. Information technology is being used to collect the information provided on this form. Individuals receiving benefits under chapter 33 do not have to verify their attendance. Chapters 30 and 1606 respondents must submit this information electronically using either the automated telephone system or the internet. The information is provided via the Toll-free automated telephone number using Interactive Voice Response technology (IVR). If the information is provided via the internet, it is collected via the Web Automated Verification of Enrollment (WAVE) system. Only respondents receiving education benefits under chapter 32 or 35, or section 903, who are enrolled in NCD programs receive the paper form. The VA extracts claimant information electronically from education data resources and places it into the appropriate blocks of VA Form 22 8979. The VA then sends the printed form for chapters 32 and 35, as well as section 903 to respondents during computer generated monthly mailings. Majority of the individuals enrolled in NCD programs verify their attendance using the Toll-free customer service number (1–888–442–4551) instead of returning the form. The number of respondents who complete and return the paper form is insignificant. Collection of this information on a monthly basis will prevent overpayment of benefits due to late reporting, since payment will not be made until the report of attendance has been returned to VA and processed. To collect information less often would preclude VA from making monthly payments as required under existing regulations.

Affected Public: Individuals or Households.

Estimated Annual Burden: 21,526 hours.

Estimated Average Burden Time Per Respondent: 1 minute.

Frequency of Response: On Occasion.

Estimated Number of Respondents: 258,313.

By direction of the Secretary.

Dorothy Glasgow,

VA PRA Clearance Officer (Alt.), Office of Enterprise and Integration/Data Governance Analytics, Department of Veterans Affairs.

[FR Doc. 2022–26455 Filed 12–5–22; 8:45 am]

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Part II

Environmental Protection Agency

40 CFR Part 60

Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2021–0317; FRL–8510–04–OAR]

RIN 2060–AV16

Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review

AGENCY: Environmental Protection Agency (EPA).

ACTION: Supplemental notice of proposed rulemaking.

SUMMARY: The EPA is issuing this supplemental proposal to update, strengthen, and expand the standards proposed on November 15, 2021 (November 2021 proposal), which are intended to significantly reduce emissions of greenhouse gases (GHGs) and other harmful air pollutants from the Crude Oil and Natural Gas source category. First, the EPA proposes standards for certain sources that were not addressed in the November 2021 proposal. Second, the EPA proposes revisions that strengthen standards for sources of leaks, provide greater flexibility to use innovative advanced detection methods, and establish a super emitter response program. Third, the EPA proposes to modify and refine certain elements of the proposed standards in response to information submitted in public comments on the November 2021 proposal. Finally, the EPA proposes details of the timelines and other implementation requirements that apply to states to limit methane pollution from existing designated facilities in the source category under the Clean Air Act (CAA).

DATES:

Comments.

Comments must be received on or before February 13, 2023. Under the Paperwork Reduction Act (PRA), OMB is required to make a decision concerning the collections of information contained in the proposed rule between 30 and 60 days after publication and submission to OMB. A comment to OMB is best assured of consideration if the Office of Management and Budget (OMB) receives it on or before January 5, 2023.

Public hearing. The EPA will hold a virtual public hearing on January 10, 2023, and January 11, 2023. See **SUPPLEMENTARY INFORMATION** for information on the hearing.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–HQ–OAR–2021–0317 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–2021–0317 in the subject line of the message.
- *Fax:* (202) 566–9744. Attention Docket ID No. EPA–HQ–OAR–2021–0317.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA–HQ–OAR–2021–0317, 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 ''Public Participation'' heading of the **SUPPLEMENTARY INFORMATION** section of this document. For further information on EPA Docket Center services and the current status, please visit us online at *https://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Ms. Karen Marsh, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–1065; fax number: (919) 541–0516; and email address: *marsh.karen@epa.gov* or Ms. Amy Hambrick, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–0964; fax number: (919) 541–0516; email address: *hambrick.amy@epa.gov.*

SUPPLEMENTARY INFORMATION:

Participation in virtual public hearing. The public hearing will be held via virtual platform on January 10, 2023, and January 11, 2023, and will convene at 10:00 a.m. Eastern Time (ET) and conclude at 8:00 p.m. ET each day. On each hearing day, 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/controlling-air-pollution-oil-and-natural-gas-industry.* If the EPA receives a high volume of registrations for the public hearing, we may continue the public hearing on January 12, 2023. The EPA does not intend to publish a document in the **Federal Register** announcing the potential addition of a third day for the public hearing or any other updates to the information on the hearing described in this document. Please monitor *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry* for any updates to the information described in this document, including information about the public hearing. For information or questions about the public hearing, please contact the public hearing team at (888) 372–8699 or by email at *SPPDpublichearing@epa.gov.*

The EPA will begin pre-registering speakers for the hearing no later than 1 business day following the publication of this document in the **Federal Register**. The EPA will accept registrations on an individual basis. To register to speak at the virtual hearing, follow the directions at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry* 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 January 5, 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/controlling-air-pollution-oil-and-natural-gas-industry.*

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 provide the EPA with a copy of their oral testimony by submitting the text of your 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.

If you require the services of an interpreter or a special accommodation such as audio description, please pre-register for the hearing with the public hearing team and describe your needs by December 13, 2022. 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–2021–0317. 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 *https://www.regulations.gov/.*

Instructions. Direct your comments to Docket ID No. EPA–HQ–OAR–2021–0317. 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 the *Instructions* section of this document. 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 OAQPS CBI Office at the email address *oaqpscbi@epa.gov,* and as described in the preceding paragraph, 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–2021–0317. 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. 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:

AMEL alternate means of emissions limitation
ANSI American National Standards Institute
APA Administrative Procedures Act
API American Petroleum Institute
ASME American Society of Mechanical Engineers
ASTM American Society for Testing and Materials
AVO audio, visual, and olfactory
AWP alternative work practice
BMP best management practices
boe barrels of oil equivalents
BSER best system of emission reduction
Btu/scf British thermal unit per standard cubic foot
°C degrees Centigrade
CAA Clean Air Act
CBI Confidential Business Information
CCR Code of Colorado Regulations
CDX EPA's Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CFR Code of Federal Regulations
CH_4 methane
CO carbon monoxide
CO_2 carbon dioxide
CO_2 Eq. carbon dioxide equivalent
CRA Congressional Review Act
CVS closed vent systems
CWA Clean Water Act
D.C. Circuit U.S. Court of Appeals for the District of Columbia Circuit
DOE Department of Energy
EAV equivalent annual value
EDF Environmental Defense Fund
EG emission guidelines
EIA U.S. Energy Information Administration
EJ environmental justice
E.O. Executive Order
EPA Environmental Protection Agency
ESD emergency shutdown devices
°F degrees Fahrenheit
FEAST Fugitive Emissions Abatement Simulation Toolkit
FR Federal Register
FRFA final regulatory flexibility analysis
g/hr grams per hour
GHG greenhouse gas
GHGI Inventory of U.S. Greenhouse Gas Emissions and Sinks
GHGRP Greenhouse Gas Reporting Program

HAP hazardous air pollutant(s)
ICR information collection request
IRFA initial regulatory flexibility analysis
IWG Interagency Working Group on the Social Cost of Greenhouse Gases
kg kilograms
low-e low emission
LDAR leak detection and repair
Mcf thousand cubic feet
METEC Methane Emissions Technology Evaluation Center
MW megawatt
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NDE no detectable emissions
NESHAP National Emissions Standards for Hazardous Air Pollutants
NGO non-governmental organization
NHV net heating value
NO_X nitrogen oxides
NSPS new source performance standards
NTTAA National Technology Transfer and Advancement Act
OAQPS Office of Air Quality Planning and Standards
OGI optical gas imaging
OMB Office of Management and Budget
$PM_{2.5}$ particulate matter with a diameter of 2.5 micrometers or less
ppm parts per million
PRA Paperwork Reduction Act
PTE potential to emit
PV present value
REC reduced emissions completion
RFA Regulatory Flexibility Act
RIA regulatory impact analysis
RULOF remaining useful life and other factors
SBAR Small Business Advocacy Review
SC-CH_4 social cost of methane
SC-GHG social cost of greenhouse gases
scf standard cubic feet
scfh standard cubic feet per hour
scfm standard cubic feet per minute
SIP state implementation plan
SO_2 sulfur dioxide
SPeCS State Planning Electronic Collaborative System
tpy tons per year
the court U.S. Court of Appeals for the District of Columbia Circuit
TAR Tribal Authority Rule
TIP tribal implementation plan
TSD technical support document
UMRA Unfunded Mandates Reform Act
U.S. United States
VCS Voluntary Consensus Standards
VOC volatile organic compounds
VRU vapor recovery unit

Organization of this document. The information in this preamble is organized as follows:

I. Executive Summary

A. Purpose of the Regulatory Action

On November 15, 2021, the EPA published a proposed rule (November 2021 proposal) that was intended to mitigate climate-destabilizing pollution and protect human health by reducing greenhouse gas (GHG) and VOC emissions from the Oil and Natural Gas Industry,[1] specifically the Crude Oil and Natural Gas source category.[2] A wide range of stakeholders, as well as state and tribal governments, submitted public comments on the November 2021 proposal. Over 470,000 public comments were submitted. Many commenters representing diverse perspectives expressed general support for the proposal and requested that the EPA further strengthen the proposed standards and make them more comprehensive. Other commenters highlighted implementation or cost concerns related to elements of the November 2021 proposal or provided specific data and information that the EPA was able to use to refine or revise several of the standards included in the November 2021 proposal.

In the November 2021 proposal, the EPA proposed new standards and emission guidelines under CAA section 111 which would be included in 40 CFR part 60 at subpart OOOOb (NSPS OOOOb) and subpart OOOOc (EG OOOOc). The purpose of this supplemental proposed rulemaking is to strengthen, update, and expand the proposed standards for certain emissions sources, including: (1) To reduce emissions from the source category more comprehensively by adding proposed standards for certain sources that were not addressed in the November 2021 proposal, revising the

[1] The EPA characterizes the Oil and Natural Gas Industry operations as being generally composed of four segments: (1) Extraction and production of crude oil and natural gas (''oil and natural gas production''), (2) natural gas processing, (3) natural gas transmission and storage, and (4) natural gas distribution.

[2] 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, commonly referred to as the ''city-gate.''

proposed requirements for fugitive emissions monitoring and repair, and establishing a super-emitter response program; (2) to encourage the deployment of innovative technologies and techniques for detecting and reducing methane emissions by providing additional options for the use of advanced monitoring; (3) to modify and refine certain elements of the proposed standards in response to concerns and information identified in an initial review of public comments on the November 2021 proposal; and (4) to provide additional information not included in the November 2021 proposal for public comment, such as the content for the new subparts that reflects the proposed standards and emission guidelines, and details of the timelines and other requirements that apply to states as they develop state plans to implement the emission guidelines.

In the November 2021 proposal, the EPA performed a comprehensive analysis of the available data from emission sources in the Crude Oil and Natural Gas source category and the latest available information on control measures and techniques to identify achievable, cost-effective measures to significantly reduce methane and VOC emissions, consistent with the requirements of section 111 of the CAA.[3] This supplemental proposal builds on that analysis to apply additional information and data provided to the Agency since the November 2021 proposal to identify areas to further strengthen standards, such as measures to address large emissions events, commonly referred to as super-emitters. If finalized and implemented, the proposed actions in this rulemaking, as detailed in the November 2021 proposal and this supplemental proposal, would lead to significant and cost-effective reductions in climate and health-harming pollution and encourage the continued development and deployment of innovative technologies to further reduce this pollution in the Crude Oil and Natural Gas source category.

This supplemental proposal comprises distinct actions:

- Update, strengthen, and/or expand on the standards proposed in November 2021 under CAA section 111(b) for methane and VOC emissions from new, modified, and reconstructed facilities that commenced construction, reconstruction, or modification after November 15, 2021,
- Update, strengthen, and/or expand the presumptive standards proposed in November 2021 as part of the CAA section 111(d) emission guidelines for methane emissions from existing designated facilities that commenced construction, reconstruction, or modification on or before November 15, 2021,
- And establish the implementation requirements for states to limit methane pollution from existing designated facilities in the source category under CAA section 111(d).

The Oil and Natural Gas Industry is the United States' largest industrial emitter of methane, a highly potent GHG.[4] Methane and VOC emissions from the Crude Oil and Natural Gas source category result from a variety of industry operations across the supply chain. As natural gas moves through the necessarily interconnected system of exploration, production, storage, processing, and transmission that brings it from wellhead to commerce, emissions primarily result from intentional venting, unintentional gas carry-through (*e.g.,* vortexing from separator drain, improper liquid level settings, liquid level control valve on an upstream separator or scrubber not seating properly at the end of an automated liquid dumping event, inefficient separation of gas and liquid phases occurring upstream of tanks allowing some gas carry-through), routine maintenance, unintentional fugitive emissions, flaring, malfunctions, abnormal process conditions, and system upsets. These emissions are associated with a range of specific equipment and practices, including leaking valves, connectors, and other components at well sites and compressor stations; leaks and vented emissions from controlled storage vessels; releases from natural gas-driven pneumatic pumps and controllers; liquids unloading at well sites; and venting or under-performing flaring of associated gas from oil wells. Technical innovations have produced a range of technologies and best practices to monitor, eliminate or minimize these emissions, which in many cases have the benefit of simultaneously reducing multiple pollutants and recovering saleable product. These technologies and best practices have been deployed by individual oil and natural gas companies, required by state regulations, reflected in regulations issued by the EPA and other Federal agencies, or utilized by various non-industry groups and research teams.

In developing this supplemental proposal, the EPA applied the latest available information to refine or supplement the analyses presented in the November 2021 proposal. This latest information provided additional insights into lessons learned from states' regulatory efforts, the emission reduction efforts of leading companies, the continued development of new and developing technologies, and peer-reviewed research from emission measurement campaigns across the United States (U.S.). As stated in the November 2021 proposal, the EPA solicited comment on all aspects of the proposed standards and stated its intent to issue a supplemental proposal that revisited and refined certain provisions of that proposal in response to information provided by the public. This supplemental proposal does just that. For instance, the EPA sought input in the November 2021 proposal on multiple aspects of the proposed approach for fugitive emissions monitoring at well sites, including the baseline emission threshold and other criteria (such as the presence of specific types of malfunction-prone equipment) that should be used to determine whether a well site is required to undertake ongoing fugitive emissions monitoring. (86 FR 63115; November 15, 2021). After considering the comments and information received, this supplemental proposal includes a revised approach for fugitive emissions monitoring at well sites utilizing modeling to establish the proposed monitoring frequency and detection method for individual sites based on the presence of specific types of equipment. In contrast to the November 2021 proposal, this supplemental proposal would establish an obligation for all well sites to routinely monitor for fugitive emissions and repair leaks found—ranging from a quarterly audio, visual, and olfactory (AVO) inspection for single wellhead-only sites to quarterly optical gas imaging (OGI) inspections for any site with significant production equipment. This revised approach to addressing fugitive emissions from well sites also would carry the monitoring requirements through the entire life of the well site and would specify the requirements for ceasing monitoring following well closures when production from the entire well site has stopped. The EPA is seeking comments about labor requirements to implement these monitoring requirements.

[3] 42 U.S.C. 7411.

[4] Emissions from EPA (2022) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020. U.S. Environmental Protection Agency, EPA 430–R–22–003. *https://www.epa.gov/ghgemissions/draft-inventory-us-greenhouse-gas-emissionsand-sinks-1990-2020.*

Super-emitter emissions events [5] were another key area in the November 2021 proposal for which the EPA solicited comment. (86 FR 63177; November 15, 2021). This supplemental proposal includes various standards that, when implemented by an owner or operator, could reduce or eliminate the occurrence of super-emitter emissions events, such as the inclusion of specific compliance assurance measures to ensure that flares are operating as designed with a continuously lit pilot. In addition, this supplemental notice proposes a super-emitter response program to trigger swift mitigation of super-emitter emissions events when they are identified through credible information provided by regulatory authorities or approved qualified third-party sources.

Content for the new subparts reflecting these proposed changes is available in the docket for this action (Docket ID No. EPA–HQ–OAR–2021–0317) and supplements the redline versions of NSPS OOOO and NSPS OOOOa provided in the November 2021 proposal (Docket ID Nos. EPA–HQ–OAR–2021–0317–0095 and EPA–HQ–OAR–2021–0317–0097). In addition, the EPA is providing an updated regulatory impact analysis (RIA) that seeks to account for the full impacts of these proposed actions.

Additionally, the EPA is seeking comment and information on the proposed provisions for the use of advanced methane measurement technologies for both periodic screening and continuous monitoring as an alternative to OGI. The revised proposal includes a matrix that provides various monitoring frequencies based on specific performance criteria a technology would need to meet in order to be used for periodic screening. In addition to this proposed matrix, this supplemental proposal includes provisions for requesting the use of alternative test method(s) that, where approved, could be used broadly for deploying these alternative technologies. Further, the EPA is proposing a framework for the use of continuous monitoring systems that provide a mass emissions rate with site-specific action levels based on changes in quarterly average emissions and on the detection of an acute large emission spike or event on a shorter term. Diverse stakeholders expressed strong interest in employing these new tools for methane identification and quantification, particularly for super-emitters, and in the EPA's creation of a regime to promote and accommodate their development and use. This proposal provides an approach for fostering those alternatives, which could provide a template for future innovation-conducive regulatory standards. The EPA is also seeking comment on the detection limits of all monitoring and inspection requirements.

Throughout this action, unless noted otherwise, the EPA is requesting comments on all aspects of the supplemental proposal to enable the EPA to develop a final rule that, consistent with our responsibilities under section 111 of the CAA, achieves the greatest possible reductions in methane and VOC emissions while remaining achievable, cost effective, and conducive to technological innovation. Because this preamble includes comment solicitations/requests on several topics and issues, we have prepared a separate memorandum that presents these comment requests by section and topic as a guide to assist commenters in preparing comments. This memorandum can be obtained from the Docket for this action (see Docket ID No. EPA–HQ–OAR–2021–0317). The title of the memorandum is ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review—Supplemental Proposed Rule Summary of Comment Solicitations.'' It is not necessary to resubmit comments that were submitted for the November 2021 proposal.

B. Summary of the Major Provisions of the Regulatory Action

This supplemental proposal includes two distinct rulemaking actions under the CAA. First, the EPA is proposing specific changes to strengthen the proposed requirements under CAA section 111(b) for methane and VOC emissions from sources that commenced construction, modification, or reconstruction after November 15, 2021. These proposed revisions to strengthen the November 15, 2021, proposed standards of performance will be in a new subpart, NSPS OOOOb, and include proposed standards for emission sources previously not regulated for this source category.

Second, pursuant to CAA section 111(d), the EPA is proposing specific revisions to strengthen the first nationwide emission guideline (EG) for states to limit methane pollution from existing designated facilities in the Crude Oil and Natural Gas source category. The proposed revisions to strengthen the November 15, 2021, proposed presumptive standards will be in a new subpart, EG OOOOc. The emissions guidelines (EG) are designed to inform states in the development, submittal, and implementation of state plans that are required to establish standards of performance for GHGs (in the form of limitations on methane) from their designated facilities in the Crude Oil and Natural Gas source category.

As CAA section 111(a)(1) requires, the standards of performance under section 111(b) and presumptive standards under section 111(d) being proposed in this action reflect ''the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated.'' [6] In this proposed supplemental rulemaking, we evaluated new data made available to the EPA and information provided from public comments on the November 2021 proposal to update the analyses and evaluate whether revisions to the proposed BSER should be considered. For any potential control measure evaluated in this action, as in the November 2021 proposal, the EPA evaluated the emission reductions achievable through these measures and employed multiple approaches to evaluate the reasonableness of control costs associated with the options under consideration. For example, in evaluating controls for reducing VOC and methane emissions from new sources, we considered a control measure's cost-effectiveness under both a ''single pollutant cost-effectiveness'' approach and a ''multipollutant cost-effectiveness'' approach, to appropriately reflect that the systems of emission reduction evaluated in this rule typically achieve reductions in multiple pollutants simultaneously and secure a multiplicity of climate and public health benefits. We also

[5] In the November 2021 proposal, the EPA solicited comment on the use of information collected by communities and others to address large emissions events, which this supplemental proposal now defines as ''super-emitter emissions events.''

[6] The EPA notes that design, equipment, work practice or operational standards established under CAA section 111(h) (commonly referred to as ''work practice standards'') reflect the ''best technological system of continuous emission reduction'' and that this phrasing differs from the ''best system of emission reduction'' phrase in the definition of ''standard of performance'' in CAA section 111(a)(1). Although the differences in these phrases may be meaningful in other contexts, for purposes of evaluating the sources and systems of emission reduction at issue in this rulemaking, the EPA has applied these concepts in an essentially comparable manner because the systems of emission reduction the EPA evaluated are all technological.

compared: (1) The capital costs that would be incurred through compliance with the proposed standards against the industry's current level of capital expenditures and (2) the annualized costs against the industry's estimated annual revenues. For a detailed discussion of the EPA's consideration of this and other BSER statutory elements, please see section III.E of this preamble, 86 FR 63133; November 15, 2021, and 86 FR 63153; November 15, 2021. Table 1 summarizes the applicability dates for the four subparts that the EPA's November 2021 proposal included.

TABLE 1—APPLICABLE DATES FOR PROPOSED SUBPARTS ADDRESSED IN THIS PROPOSED ACTION

Subpart	Source type	Applicable dates
40 CFR part 60, subpart OOOO	New, modified, or reconstructed sources.	After August 23, 2011, and on or before September 18, 2015.
40 CFR part 60, subpart OOOOa	New, modified, or reconstructed sources.	After September 18, 2015, and on or before November 15, 2021.
40 CFR part 60, subpart OOOOb	New, modified, or reconstructed sources.	After November 15, 2021.[1]
40 CFR part 60, subpart OOOOc	Existing sources	On or before November 15, 2021.[2]

[1] The standards for dry seal centrifugal compressors will apply to those for which construction, reconstruction, or modification commenced after December 6, 2022.

[2] The presumptive standards for dry seal centrifugal compressors will apply to those for which construction, reconstruction, or modification commenced on or before December 6, 2022.

1. Proposed Standards for New, Modified and Reconstructed Sources After November 15, 2021 (Proposed NSPS OOOOb)

As described in section IV of this preamble, the EPA is proposing several changes to the BSER and the standards for certain affected facilities based on a review of new data made available to the EPA and information provided in public comments. For the other standards proposed in the November 2021 proposal that generally remain unchanged in this action, we have provided further justifications or clarifications as needed based on the public comments and other additional information received, as described in section IV of this preamble. The proposed NSPS would apply to new, modified, and reconstructed emission sources across the Crude Oil and Natural Gas source category, including the production, processing, transmission, and storage segments, for which construction, reconstruction, or modification commenced after November 15, 2021, which is the date of publication of the proposed NSPS OOOOb. In addition, the EPA is proposing methane and VOC standards for one new emission source that is currently unregulated (*i.e.,* dry seal centrifugal compressors). Because standards for dry seal centrifugal compressors were not proposed in the November 2021 proposal, new, modified, and reconstructed dry seal centrifugal compressors are defined as those for which construction, reconstruction, or modification commenced after December 6, 2022.

In particular, this action proposes revisions to strengthen the proposed VOC and methane standards addressing fugitive emissions from well sites and pneumatic pumps; generally leaves unchanged the proposed sulfur dioxide (SO_2) performance standard for sweetening units and the proposed VOC and methane performance standards for well completions, gas well liquids unloading operations, associated gas from oil wells, wet seal centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels, fugitive emissions from compressor stations, and equipment leaks at natural gas processing plants; and proposes new VOC and methane standards for dry seal centrifugal compressors previously not regulated. A summary of the proposed BSER determination and proposed NSPS for new, modified, and reconstructed sources (NSPS OOOOb) is presented in Table 2. See section IV of this preamble for a complete discussion of the proposed changes to the BSER determination and proposed NSPS requirements.

This proposal also includes provisions for the use of alternative test methods using advanced methane detection technologies that allow for periodic screening or continuous monitoring for fugitive emissions and emissions from covers and closed vent systems (CVS) used to route emissions to control devices. These proposed alternatives would allow for advanced screening technologies, which could be used to identify large emissions or ''super-emitter emissions events'' sooner than the proposed use of periodic OGI monitoring for fugitive emissions, covers on storage vessels, and CVS. Various studies using aerial monitoring techniques have identified large emissions from these types of sources. Finally, in order to ensure that super-emitter emissions events are identified and mitigated as quickly as possible, the EPA is proposing a super-emitter response program where an owner or operator must investigate and take appropriate mitigation actions upon receiving certified notifications of detected emissions that are 100 kg/hr of methane or greater. See sections IV.A and IV.B of this preamble for a complete discussion of these proposed provisions.

2. Proposed EG for Sources Constructed Prior to November 15, 2021 (Proposed EG OOOOc)

As described in sections IV and V of this preamble, the EPA is proposing several changes to the BSER determinations and presumptive standards that were proposed under the authority of CAA section 111(d) in the November 2021 proposal. These changes are based on a review of new data made available to the EPA and information provided in public comments. In the November 2021 proposal the EPA proposed the first nationwide EG for GHG (in the form of methane limitations) for the Crude Oil and Natural Gas source category, including the production, processing, transmission, and storage segments (EG OOOOc).

This action proposes revisions to strengthen the proposed presumptive standards for methane addressing fugitive emissions from well sites, pneumatic controllers, pneumatic pumps, and wet seal centrifugal compressors; generally leaves unchanged the proposed methane presumptive standards for associated gas from oil wells, reciprocating compressors, storage vessels, fugitive emissions from compressor stations, and equipment leaks at natural gas processing plants; and proposes new methane presumptive standards for well liquids unloading operations and dry seal centrifugal compressors previously not proposed to be regulated. A summary of the proposed BSER determination and proposed presumptive standards for EG OOOOc is presented in Table 3. See section IV of this preamble for a complete discussion of the proposed changes to the BSER determination and proposed presumptive standards.

This proposal also includes the same provisions described for NSPS OOOOb that allow for the use of alternative test methods using advanced methane detection technologies for periodic screening or continuous monitoring for fugitive emissions and emissions from covers and CVS used to route emissions to control devices. Finally, the EPA is also proposing a super-emitter response program, where an owner or operator that receives certified notifications of detected emissions that are 100 kg/hr or greater is obligated to take action to address those emissions. See sections IV.A and IV.B of this preamble for a complete discussion of these proposed provisions.

As stated in the November 2021 proposal,[7] when the EPA establishes NSPS for a source category, the EPA is required to issue EG to reduce emissions of certain pollutants from existing sources in that same source category. In such circumstances, under CAA section 111(d), the EPA must issue regulations to establish procedures under which states submit plans to establish, implement, and enforce standards of performance for existing sources for certain air pollutants to which a Federal NSPS would apply if such existing source were a new source. Thus, the issuance of CAA section 111(d) final EG does not impose binding requirements directly on sources but instead provides requirements for states in developing their plans. Although state plans bear the obligation to establish standards of performance, under CAA sections 111(a)(1) and 111(d), those standards of performance must reflect the degree of emission limitation achievable through the application of the BSER as determined by the Administrator. As provided in CAA section 111(d), a state may choose to take into account remaining useful life and other factors in applying a standard of performance to a particular source, consistent with the CAA, the EPA's implementing regulations, and the final EG.

In this supplemental proposal, the EPA is proposing changes to the BSER determinations and the degree of limitation achievable through application of the BSER for certain existing equipment, processes, and activities across the Crude Oil and Natural Gas source category. Those changes are discussed in section IV of this preamble. Section V of this preamble discusses the components of EG, including the steps, requirements, and considerations associated with the development, submittal, and implementation of state, tribal, and Federal plans, as appropriate. For the EG, the EPA is proposing to translate the degree of emission limitation achievable through application of the BSER (*i.e.,* level of stringency) into presumptive standards that states may use in the development of state plans for specific designated facilities. By doing this, the EPA has formatted the proposed EG such that if a state chooses to adopt these presumptive standards, once finalized, as the standards of performance in a state plan, the EPA could approve such a plan as meeting the requirements of CAA section 111(d) and the finalized EG, if the plan meets all other applicable requirements. In this way, the presumptive standards included in the EG serve a function similar to that of a model rule,[8] because they are intended to assist states in developing their plan submissions by providing states with a starting point for standards that are based on general industry parameters and assumptions. The EPA anticipates that providing these presumptive standards will create a streamlined approach for states in developing plans and the EPA in evaluating state plans. However, the EPA's action on each state plan submission is carried out via rulemaking, which includes public notice and comment. Inclusion of presumptive standards in the EG does not seek to pre-determine the outcomes of any future rulemaking.

Designated facilities located in Indian country would not be encompassed within a state's CAA section 111(d) plan. Instead, an eligible tribe that has one or more designated facilities located in its area of Indian country would have the opportunity, but not the obligation, to seek authority and submit a plan that establishes standards of performance for those facilities on its Tribal lands. If a tribe does not submit a plan, or if the EPA does not approve a tribe's plan, then the EPA has the authority to establish a Federal plan for that tribe. A summary of the proposed EG for existing sources (EG OOOOc) for the oil and natural gas sector is presented in Table 3. See sections IV and V of this preamble for a complete discussion of the proposed EG requirements.

TABLE 2—SUMMARY OF PROPOSED BSER AND PROPOSED STANDARDS OF PERFORMANCE FOR GHGs AND VOCs
[NSPS OOOOb]

Affected source	Proposed BSER	Proposed standards of performance for GHGs and VOCs
Super-Emitters	Root cause analysis and corrective action following notification of super-emitter emissions event.	Root cause analysis and corrective action following notification of super-emitter emissions event.
Fugitive Emissions: Single Wellhead Only Well Sites and Small Well Sites.	Quarterly AVO inspections	Quarterly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Multi-wellhead Only Well Sites (2 or more wellheads).	Quarterly AVO inspections AND	Quarterly AVO inspections. Repair for indications of potential leaks within 15 days of inspection.

[7] See 86 FR 63117 (November 15, 2021).

[8] The presumptive standards are not the same as a Federal plan under CAA section 111(d)(2). The EPA has an obligation to promulgate a Federal plan if a state fails to submit a satisfactory plan. In such circumstances, the final EG and presumptive standards would serve as a guide to the development of a Federal plan. See section VIII.F. for information on Federal plans.

TABLE 2—SUMMARY OF PROPOSED BSER AND PROPOSED STANDARDS OF PERFORMANCE FOR GHGS AND VOCS—Continued

[NSPS OOOOb]

Affected source	Proposed BSER	Proposed standards of performance for GHGs and VOCs
	Monitoring and repair based on semiannual monitoring using OGI [2].	Semiannual OGI monitoring (Optional semiannual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Well Sites with Major Production and Processing Equipment and Centralized Production Facilities.	Bimonthly AVO monitoring (*i.e.,* every other month). AND Well sites with specified major production and processing equipment: Monitoring and repair based on quarterly monitoring using OGI.	Bimonthly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. AND Well sites with specified major production and processing equipment: Quarterly OGI monitoring. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Compressor Stations	Monthly AVO monitoring AND Monitoring and repair based on quarterly monitoring using OGI.	Monthly AVO monitoring. AND Quarterly OGI monitoring. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations on Alaska North Slope.	Monitoring and repair based on annual monitoring using OGI.	Annual OGI monitoring. (Optional annual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations.	(Optional) Screening, monitoring, and repair based on periodic screening using an advanced measurement technology instead of OGI monitoring.	(Optional) Alternative periodic screening with advanced measurement technology instead of OGI and AVO monitoring according to minimum detection sensitivity of technology.
Fugitive Emissions: Well Sites and Compressor Stations.	(Optional) Monitoring and repair based on using a continuous monitoring system instead of OGI monitoring.	(Optional) Alternative continuous monitoring system instead of OGI and AVO monitoring.
Storage Vessels: A Single Storage Vessel or Tank Battery with PTE [4] of 6 tpy or more of VOC and PTE of 20 tpy or more of methane.	Capture and route to a control device	95 percent reduction of VOC and methane.
Pneumatic Controllers: Natural gas-driven that Vent to the Atmosphere.	Use of zero-emissions controllers	VOC and methane emission rate of zero.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—continuous bleed natural gas-driven).	Use of low-bleed pneumatic controllers	Natural gas bleed rate no greater than 6 scfh.[5]
Pneumatic Controllers: Alaska (at sites where onsite power is not available—intermittent natural gas-driven).	Monitor and repair through fugitive emissions program.	OGI monitoring and repair of emissions from controller malfunctions.
Well Liquids Unloading	Employ techniques or technologies that eliminate methane and VOC emissions. If this is not feasible for safety or technical reasons, employ best management practices to minimize venting of emissions to the maximum extent possible.	Perform liquids unloading with zero methane or VOC emissions. If this is not feasible for safety or technical reasons, employ best management practices to minimize venting of emissions to the maximum extent possible.
Wet Seal Centrifugal Compressors (except for those located at well sites).	Capture and route emissions from the wet seal fluid degassing system to a control device.	95 percent reduction of methane and VOC emissions.
Dry Seal Centrifugal Compressors (except for those located at well sites).	Conduct preventative maintenance and repair to maintain flow rate at or below 3 scfm [7].	Volumetric flow rate of 3 scfm.

TABLE 2—SUMMARY OF PROPOSED BSER AND PROPOSED STANDARDS OF PERFORMANCE FOR GHGS AND VOCS—Continued

[NSPS OOOOb]

Affected source	Proposed BSER	Proposed standards of performance for GHGs and VOCs
Reciprocating Compressors (except for those located at well sites).	Repair or replace the reciprocating compressor rod packing in order to maintain a flow rate at or below 2 scfm.	Volumetric flow rate of 2 scfm.
Pneumatic Pumps	Use of zero-emission pumps that are not powered by natural gas.	Methane and VOC emission rate of zero.
Well Completions: Subcategory 1 (non-wildcat and non-delineation wells).	Combination of REC[8] and the use of a completion combustion device.	Applies to each well completion operation with hydraulic fracturing. REC in combination with a completion combustion device; venting in lieu of combustion where combustion would present demonstrable safety hazards. Initial flowback stage: Route to a storage vessel or completion vessel (frac tank, lined pit, or other vessel) and separator. Separation flowback stage: Route all salable gas from the separator to a flow line or collection system, re-inject the gas into the well or another well, use the gas as an onsite fuel source or use for another useful purpose that a purchased fuel or raw material would serve. If technically infeasible to route recovered gas as specified, recovered gas must be combusted. All liquids must be routed to a storage vessel or well completion vessel, collection system, or be re-injected into the well or another well. The operator is required to have (and use) a separator onsite during the entire flowback period.
Well Completions: Subcategory 2 (exploratory, wildcat, and delineation wells and low-pressure wells).	Use of a completion combustion device	Applies to each well completion operation with hydraulic fracturing. The operator is not required to have a separator onsite. Either: (1) Route all flowback to a completion combustion device with a continuous pilot flame; or (2) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device with a continuous pilot flame. For both options (1) and (2), combustion is not required in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways.
Equipment Leaks at Natural Gas Processing Plants.	LDAR[9] with bimonthly OGI	LDAR with OGI following procedures in appendix K.
Oil Wells with Associated Gas	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions.	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source or used for another useful purpose that a purchased fuel or raw material would serve. If demonstrated that a sales line and beneficial uses are not technically feasible, the gas can be routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions.
Sweetening Units	Achieve SO_2 emission reduction efficiency	Achieve required minimum SO_2 emission reduction efficiency.

[1] tpy (tons per year).
[2] OGI (optical gas imaging).
[3] ppm (parts per million).
[4] PTE (potential to emit).

[5] scfh (standard cubic feet per hour).
[6] BMP (best management practices).
[7] scfm (standard cubic feet per minute).
[8] REC (reduced emissions completion).
[9] LDAR (leak detection and repair).

TABLE 3—SUMMARY OF PROPOSED BSER AND PROPOSED PRESUMPTIVE STANDARDS FOR GHGS FROM DESIGNATED FACILITIES (EG OOOOc)

Designated facility	Proposed BSER	Proposed presumptive standards for GHGs
Super-Emitters	Root cause analysis and corrective action following notification of super-emitter emissions event.	Root cause analysis and corrective action following notification by an EPA-approved entity or regulatory authority of a super-emitter emissions event.[9]
Fugitive Emissions: Single Wellhead Only Well Sites and Small Well Sites.	Quarterly AVO inspections	Quarterly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Multi-wellhead Only Well Sites (2 or more wellheads).	Quarterly AVO inspections AND Monitoring and repair based on semiannual monitoring using OGI[2].	Quarterly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. Semiannual OGI monitoring (Optional semiannual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Well Sites and Centralized Production Facilities.	Bimonthly AVO monitoring (*i.e.,* every other month). AND Well sites with specified major production and processing equipment: Monitoring and repair based on quarterly monitoring using OGI.	Bimonthly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. AND Well sites with specified major production and processing equipment: Quarterly OGI monitoring. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Compressor Stations	Monthly AVO monitoring AND Monitoring and repair based on quarterly monitoring using OGI.	Monthly AVO monitoring. AND Quarterly OGI monitoring. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations on Alaska North Slope.	Monitoring and repair based on annual monitoring using OGI.	Annual OGI monitoring. (Optional annual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations.	(Optional) Screening, monitoring, and repair based on periodic screening using an advanced measurement technology instead of OGI monitoring.	(Optional) Alternative periodic screening with advanced measurement technology instead of OGI monitoring.
Fugitive Emissions: Well Sites and Compressor Stations.	(Optional) Monitoring and repair based on using a continuous monitoring system instead of OGI monitoring.	(Optional) Alternative continuous monitoring system instead of OGI monitoring.
Storage Vessels: Tank Battery with PTE of 20 tpy or More of Methane.	Capture and route to a control device	95 percent reduction of methane.
Pneumatic Controllers: Natural gas-driven that Vent to the Atmosphere.	Use of zero-emissions controllers	Methane emission rate of zero.

TABLE 3—SUMMARY OF PROPOSED BSER AND PROPOSED PRESUMPTIVE STANDARDS FOR GHGS FROM DESIGNATED FACILITIES (EG OOOOc)—Continued

Designated facility	Proposed BSER	Proposed presumptive standards for GHGs
Pneumatic Controllers: Alaska (at sites where onsite power is not available—continuous bleed natural gas-driven).	Use of low-bleed pneumatic controllers	Natural gas bleed rate no greater than 6 scfh.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—intermittent natural gas-driven).	Monitor and repair through fugitive emissions program.	OGI monitoring and repair of emissions from controller malfunctions.
Gas Well Liquids Unloading	Employ techniques or technologies that eliminate methane emissions. If this is not feasible for safety or technical reasons, employ best management practices to minimize venting of emissions to the maximum extent possible.	Perform liquids unloading with zero methane emissions. If this is not feasible for safety or technical reasons, employ best management practices to minimize venting of emissions to the maximum extent possible.
Wet Seal Centrifugal Compressors (except for those located at well sites).	Conduct preventative maintenance and repair to maintain flow rate at or below 3 scfm[7].	Volumetric flow rate of 3 scfm.
Dry Seal Centrifugal Compressors (except for those located at well sites).	Conduct preventative maintenance and repair to maintain flow rate at or below 3 scfm[7].	Volumetric flow rate of 3 scfm.
Reciprocating Compressors (except for those located at well sites).	Repair or replace the reciprocating compressor rod packing in order to maintain a flow rate at or below 2 scfm.	Volumetric flow rate of 2 scfm.
Pneumatic Pumps	Use of zero-emission pumps that are not powered by natural gas.	Methane emission rate of zero.
Equipment Leaks at Natural Gas Processing Plants.	LDAR with bimonthly OGI	LDAR with OGI following procedures in appendix K.
Oil Wells with Associated Gas	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane emissions.	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source or used for another useful purpose that a purchased fuel or raw material would serve. If demonstrated that a sales line and beneficial uses are not technically feasible, the gas can be routed to a flare or other control device that achieves at least 95 percent reduction in methane emissions.

C. Costs and Benefits

In accordance with the requirements of Executive Order (E.O.) 12866, the EPA projected the emissions reductions, costs, and benefits that may result from this proposed action if finalized as proposed. These results are presented in detail in the RIA accompanying this proposal developed in response to E.O. 12866. The RIA focuses on the elements of the proposed rule that are likely to result in quantifiable cost or emissions changes compared to a baseline that incorporates changes to the regulatory requirements induced by the Congressional Review Act (CRA) resolution[10] but does not incorporate the proposed standards. We estimated the cost, emissions, and benefit impacts for the 2023 to 2035 period. We present the present value (PV) and equivalent annual value (EAV) of costs, benefits, and net benefits of this action in 2019 dollars.

The initial analysis year in the RIA is 2023 as we assume the proposed rule will be finalized early in 2023. The NSPS will take effect immediately and impact sources constructed after publication of the proposed rule. The EG will take longer to go into effect as states will need to develop implementation plans in response to the rule and have them approved by the EPA. We assume in the RIA that this process will take 3 years, and so EG impacts will begin in 2026. The final analysis year is 2035, which allows us to provide 10 years of projected impacts after the EG is assumed to take effect.

The cost analysis presented in the RIA reflects a nationwide engineering analysis of compliance cost and emissions reductions, of which there are two main components. The first component is a set of representative or model plants for each regulated facility, segment, and control option. The characteristics of the model plant include typical equipment, operating characteristics, and representative factors including baseline emissions and the costs, emissions reductions, and product recovery resulting from each control option. The second component is a set of projections of activity data for affected facilities, distinguished by vintage, year, and other necessary attributes (*e.g.,* oil versus natural gas wells). Impacts are calculated by setting parameters on how and when affected facilities are assumed to respond to a particular regulatory regime, multiplying activity data by model plant cost and emissions estimates, differencing from the baseline scenario, and then summing to the desired level of aggregation. In addition to emissions reductions, some control options result in natural gas recovery, which can then be combusted in production or sold. Where applicable, we present projected compliance costs with and without the projected revenues from product recovery.

The EPA expects climate and health benefits due to the emissions reductions projected under this proposed rule. The EPA estimated the climate benefits of

[9] As described in section IV.C, the EPA is proposing a super-emitter response program under the statutory rationale that super-emitters are a designated facility. The EPA is also proposing the program under a second rationale that the super-emitter response program constitutes work practice standards for certain sources and compliance assurance measures for other sources. Under either rationale, state plans are generally required to adopt the super-emitter response program either as presumptive standards or as measures that provide for the implementation and enforcement of such standards.

[10] See November 2021 Proposal, 86 FR at 63116 (discussing the CRA Resolution and its effect on regulatory requirements).

methane (CH_4) emission reductions expected from this proposed rule using the social cost of methane (SC-CH_4) estimates presented in the ''Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under E.O. 13990'' (IWG 2021) published in February 2021 by the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG). As a member of the IWG involved in the development of the February 2021 TSD, the EPA agrees that these estimates continue to represent at this time the most appropriate estimate of the SC-CH_4 until revised estimates have been developed reflecting the latest, peer-reviewed science. However, as discussed in Section VII.E, the EPA also presents a sensitivity analysis of the monetized climate benefits using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017). The EPA notes that the benefits analysis is entirely distinct from the statutory BSER determinations proposed herein and is presented solely for the purposes of complying with E.O. 12866.

Under the proposed rule, the EPA expects that VOC emission reductions will improve air quality and are likely to improve health and welfare associated with exposure to ozone, particulate matter with a diameter of 2.5 micrometers or less ($PM_{2.5}$), and hazardous air pollutants (HAP). Calculating ozone impacts from VOC emissions changes requires information about the spatial patterns in those emissions changes. In addition, the ozone health effects from the proposed rule will depend on the relative proximity of expected VOC and ozone changes to population. In this analysis, we have not characterized VOC emissions changes at a finer spatial resolution than the national total. In light of these uncertainties, we present an illustrative screening analysis in appendix C of the RIA based on modeled oil and natural gas VOC contributions to ozone concentrations as they occurred in 2017 and do not include the results of this analysis in the estimate of benefits and net benefits projected from this proposal.

The projected national-level emissions reductions over the 2023 to 2035 period anticipated under the proposed requirements are presented in Table 4. Table 5 presents the PV and EAV of the projected benefits, costs, and net benefits over the 2023 to 2035 period under the proposed requirements using discount rates of 3 and 7 percent. The estimates presented in Tables 4 and 5 reflect an updated analysis compared with the RIA that accompanied the November 2021 proposal. The updated analysis not only incorporates the new provisions put forth in the supplemental proposal (in addition to the elements of the November 2021 proposal that are unchanged), but also includes key updates to assumptions and methodologies that impact both the baseline and policy scenarios. As such, the estimates presented in the tables are not directly comparable to corresponding estimates presented in the November 2021 proposal. Additionally, we note that the estimated emission reductions in both proposals may not fully characterize the emissions reductions achieved by this rule because they might not fully account for the emissions resulting from super-emitter emissions events that would be prevented or quickly corrected as a result of this rule.

The EPA solicits comments on any relevant data, appropriate methodologies, or reliable estimates to help quantify the costs, emissions reductions, benefits, and potential distributional effects related to super-emitter events, the proposed emissions control requirements for associated gas from oil wells, and the proposed storage vessel control requirements at centralized production facilities and in the gathering and boosting segment.

TABLE 4—PROJECTED EMISSIONS REDUCTIONS UNDER THE PROPOSED RULE, 2023–2035 TOTAL

Pollutant	Emissions reductions (2023–2035 total)
Methane (million short tons) [a]	36
VOC (million short tons)	9.7
Hazardous Air Pollutant (million short tons)	0.39
Methane (million metric tons CO_2 Eq.) [b]	810

[a] To convert from short tons to metric tons, multiply the short tons by 0.907. Alternatively, to convert metric tons to short tons, multiply metric tons by 1.102.
[b] Carbon dioxide equivalent (CO_2 Eq.) calculated using a global warming potential of 25.

TABLE 5—BENEFITS, COSTS, NET BENEFITS, AND EMISSIONS REDUCTIONS OF THE PROPOSED RULE, 2023 THROUGH 2035

[Dollar estimates in millions of 2019 dollars] [a]

	Present value	Equivalent annual value	Present value	Equivalent annual value
	3 Percent Discount Rate			
Climate Benefits [b]	$48,000	$4,500	$48,000	$4,500
	3 Percent Discount Rate		7 Percent Discount Rate	
Net Compliance Costs	$14,000	$1,400	$12,000	$1,400
Compliance Costs	19,000	1,800	15,000	1,800
Product Recovery	4,600	440	3,300	390
Net Benefits	34,000	3,200	36,000	3,100
Non-Monetized Benefits	Climate and ozone health benefits from reducing 36 million short tons of methane from 2023 to 2035. $PM_{2.5}$ and ozone health benefits from reducing 9.7 million short tons of VOC from 2023 to 2035.[c] HAP benefits from reducing 390 thousand short tons of HAP from 2023 to 2035.			

TABLE 5—BENEFITS, COSTS, NET BENEFITS, AND EMISSIONS REDUCTIONS OF THE PROPOSED RULE, 2023 THROUGH 2035—Continued

[Dollar estimates in millions of 2019 dollars] [a]

	Present value	Equivalent annual value	Present value	Equivalent annual value
	Emissions reductions from the super-emitter response program. Visibility benefits. Reduced vegetation effects.			

[a] Values rounded to two significant figures. Totals may not appear to add correctly due to rounding.

[b] Climate benefits are based on reductions in methane emissions and are calculated using four different estimates of the SC-CH_4 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For the presentational purposes of this table, we show the benefits associated with the average SC-CH_4 at a 3 percent discount rate, but the Agency does not have a single central SC-CH_4 point estimate. We emphasize the importance and value of considering the benefits calculated using all four SC-CH_4 estimates; the present value (and equivalent annual value) of the additional benefit estimates ranges from $19 billion to $130 billion ($2.1 billion to 12 billion) over 2023 to 2035 for the proposed option. Please see Table 3–5 and Table 3–8 of the RIA for the full range of SC-CH_4 estimates. As discussed in Section 3 of the RIA, a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts. Appendix B of the RIA presents the results of a sensitivity analysis using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017). All net benefits are calculated using climate benefits discounted at 3 percent.

[c] A screening-level analysis of ozone benefits from VOC reductions can be found in appendix C of the RIA, which is included in the docket.

II. General Information

A. Does this action apply to me?

Categories and entities potentially affected by this action include:

TABLE 6—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211120	Crude Petroleum Extraction.
	211130	Natural Gas Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal Government		Not affected.
State/local/tribal government		Not affected.

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

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be affected by this action. Other types of entities not listed in the table could also be affected by this action. To determine whether your entity is affected by this action, you should carefully examine the applicability criteria found in the final rule. 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, your air permitting authority, or your EPA Regional representative listed in 40 CFR 60.4 (General Provisions).

B. How do I obtain a copy of this document, background information, and other related information?

In addition to being available in the docket, an electronic copy of the proposed action is available on the internet. Following signature by the Administrator, the EPA will post a copy of this proposed action at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version of the supplemental proposal and key technical documents at this same website and at Docket ID No. EPA–HQ–OAR–2021–0317 located at *https://www.regulations.gov/.*

III. Purpose of This Regulatory Action

A. What is the purpose of this supplemental proposal?

On November 15, 2021, the EPA published a proposed rulemaking that included proposed NSPS and EGs to mitigate climate-destabilizing pollution and to protect human health by reducing GHG and VOC emissions from the Oil and Natural Gas Industry, specifically the Crude Oil and Natural Gas source category. The November 2021 proposal included comprehensive analyses of the available data for methane and VOC emissions sources in the Crude Oil and Natural Gas source category and the latest available information on control measures and techniques to identify achievable, cost-effective measures to significantly reduce emissions, consistent with the requirements of section 111 of the CAA. The November 2021 proposal also solicited comment and information on specific topics.

New information was received and reviewed that was not considered in the November 2021 proposal. As a result, changes to some of the standards and other provisions proposed in November 2021 are being proposed in this supplemental notice.

Some of the new information was provided by commenters during the November 2021 proposal public comment period. Approximately 470,000 public comment letters were submitted on the November 2021 proposal representing a wide range of stakeholders and state and tribal governments. The EPA reviewed and considered the comments received, including the responses to the specific solicitations for information and input in the development of this supplemental proposal. Several of the commenters representing diverse stakeholder perspectives expressed general support for the proposal and requested that the EPA further strengthen the proposed standards and make them more comprehensive. Other commenters highlighted implementation or cost concerns related to some of the elements proposed in the November 2021 proposal. Some commenters also provided data and information that the EPA was able to use to refine or revise several of the standards included in the November 2021 proposal.

This supplemental proposal only addresses specific comments that the EPA determined warranted changes to what was proposed. It does not address/summarize all of the comments submitted on the November 2021 proposal. The EPA will continue to evaluate all the previously submitted comments, as well as new comments submitted on this supplemental action, in the development of a final NSPS OOOOb and EG OOOOc. All relevant comments submitted on both proposals will be responded to at that time.

In summary, the purpose of this supplemental proposed rulemaking is to update, strengthen, and expand the standards proposed in the November 2021 proposal under CAA section 111(b) for methane and VOC emissions from new, modified, and reconstructed facilities, and the presumptive standards proposed under CAA section 111(d) for methane emissions from existing sources. In addition, this proposal: (1) Proposes to reduce emissions from the source category more comprehensively by adding proposed standards for certain sources that were not addressed in the November 2021 proposal, revising the proposed requirements for fugitive emissions monitoring and repair, and by establishing a super-emitter response program to target timely mitigation of super-emitter emissions events; (2) encourages the deployment of innovative technologies and techniques for detecting and reducing methane emissions by providing additional options for the use of advanced monitoring; (3) modifies and refines certain aspects of the proposed standards in response to concerns and information submitted in public comments; and (4) provides additional information not included in the November 2021 proposal for public comment, such as content for the new subparts that reflects the proposed standards and emission guidelines, and details of the timelines and other implementation requirements that apply to states to limit methane pollution from existing designated facilities in the source category under CAA section 111(d).

This supplemental notice also includes an updated RIA that accounts for the full impacts of these proposed actions. If finalized and implemented, the proposed actions in this rulemaking, as detailed in the November 2021 proposal and this supplemental proposal, would result in significant and cost-effective reductions in climate and health-harming pollution while encouraging the continued development and deployment of innovative technologies to further reduce this pollution in the Crude Oil and Natural Gas source category.

The summary and rationale for changes to the November 2021 proposed NSPS OOOOb and EG OOOOc standards are presented in section IV of this preamble. For each change, a high-level summary of the relevant points raised by commenters leading to the change is provided, followed by the EPA's rationale for the change. In addition to changes from the November 2021 proposal that are the result of public comments, the EPA has also included changes made as a result of additional EPA review and consideration of available information.

Section V of this preamble proposes specific requirements for the implementation of the proposed EG to provide states with information needed for purposes of EG state plan development. First, we discuss changes to the proposed requirements for establishing standards of performance in state plans. Second, we discuss changes to the proposed components of an approvable state plan submission. Third, we discuss the proposed timing for state plan submissions, and changes to the proposed timeline for designated facilities to come into final compliance with the state plan.

Section VI of this preamble includes requirements for using optical gas imaging in leak detection as appendix K to 40 CFR part 60 (appendix K). It provides an overview of the November 2021 proposal, significant changes made to the proposal and the basis for those changes, and a summary of the updated appendix K requirements.

Section VII of this supplemental proposal includes updates to the impacts of the November 2021 NSPS proposal based on changes discussed in sections IV and V of this preamble.

The EPA is requesting comments on all aspects of the supplemental proposal to enable the EPA to develop a final rule that, consistent with our responsibilities under section 111 of the CAA, achieves the greatest possible reductions in methane and VOC emissions while remaining achievable, cost effective, and conducive to technological innovation. Because this preamble includes comment solicitations/requests on several topics and issues, we have prepared a separate memorandum that presents these comment requests by section and topic as a guide to assist commenters in preparing comments. This memorandum and supporting materials can be obtained from the Docket for this action (see Docket ID No. EPA–HQ–OAR–2021–0317). The title of the memorandum is ''Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review—Supplemental Proposed Rule Summary of Comment Solicitations.''

B. What date defines a new, modified, or reconstructed source for purposes of the proposed NSPS OOOOb?

For the reasons explained below, NSPS OOOOb would apply to all emissions sources (''affected facilities'') identified in the proposed 40 CFR 60.5365b, except dry seal centrifugal compressors, that commenced construction, reconstruction, or modification after November 15, 2021. NSPS OOOOb would apply to dry seal centrifugal compressor affected facilities that commence construction, reconstruction, or modification after December 6, 2022.

Pursuant to CAA section 111(b), the EPA proposed new source performance standards (NSPS) for a wide range of emissions sources in the Crude Oil and Natural Gas source category (to be codified in 40 CFR part 60 subpart OOOOb) in a **Federal Register** notice published November 15, 2021. Some of the proposed standards resulted from the EPA's review of the current NSPS codified at 40 CFR part 60 subpart OOOOa (NSPS OOOOa), while others were proposed standards for additional emissions sources that are currently unregulated. The emissions sources for which the EPA proposed standards in the November 2021 proposal are as follows:

- Well completions
- Gas well liquids unloading operations
- Associated gas from oil wells
- Wet seal centrifugal compressors
- Reciprocating compressors
- Pneumatic controllers
- Pneumatic pumps
- Storage vessels
- Collection of fugitive emissions components at well sites, centralized production facilities, and compressor stations
- Equipment leaks at natural gas processing plants

- Sweetening units

These standards of performance would apply to ''new sources.'' CAA section 111(a)(2) defines a ''new source'' as ''any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.'' Because the proposed regulation proposing the standards for these emission sources was published November 15, 2021, ''new sources'' to which these standards apply are those that commenced construction, reconstruction, or modification after November 15, 2021.

We received comments on the November 2021 proposal that it lacks regulatory text and therefore should not be used to define new sources for purposes of NSPS OOOOb.[11] The EPA disagrees for the following reasons. CAA section 307(d)(3) specifies the information that a proposed rule under the CAA must contain, such as a statement of basis, supporting data, and major legal and policy considerations; the list of required information does not include proposed regulatory text. Similarly, the Administrative Procedures Act (APA), which governs most Federal rulemaking, does not require publication of the proposed regulatory text in the **Federal Register**. Section 553(b)(3) of the APA provides that a notice of proposed rulemaking shall include ''*either* the terms or substance of the proposed rule *or* a description of the subjects and issues involved.'' (Emphasis added). Thus, the APA clearly provides flexibility to describe the ''subjects and issues involved'' as an alternative to inclusion of the ''terms or substance'' of the proposed rule. See also *Rybachek* v. *EPA,* 904 F.2d 1276, 1287 (9th Cir. 1990) (the EPA's ''failure to propose in advance the actual wording'' of a regulation does not make the regulation invalid where the ''proposal . . . clearly describe[s] 'the subjects and issues' '' involved). The EPA solicits comments on whether CAA section 111(a) provides the EPA discretion to define ''new sources'' based on the publication date of a supplemental proposal and, if so, whether there are any unique circumstances here that would warrant the exercise of such discretion in this rulemaking by the EPA.

In addition to the proposed standards, this supplemental proposal includes proposed standards for an additional emissions source, specifically dry seal centrifugal compressors. Because the EPA is proposing standards for dry seal centrifugal compressors for the first time in this supplemental proposal, ''new sources'' to which these standards apply are dry seal centrifugal compressors that commence construction, reconstruction, or modification after the date this supplemental proposal is published, which is December 6, 2022.

C. What date defines an existing source for purposes of the proposed EG OOOOc?

The November 2021 proposal also included proposed emissions guidelines for states to follow and develop plans to regulate existing sources in the Crude Oil and Natural Gas source category under EG OOOOc. Under CAA section 111, a source is either new, *i.e.,* construction, reconstruction, or modification commenced after a proposed NSPS is published in the **Federal Register** (CAA section 111(a)(1)), or existing, *i.e.,* any source other than a new source (CAA section 111(a)(6)). Accordingly, any source that is not subject to the proposed NSPS OOOOb as described is an existing source subject to EG OOOOc. As explained, new sources, with the exception of dry seal centrifugal compressors, are those that commenced construction, reconstruction, or modification after November 15, 2021; therefore, existing sources are those that commenced construction, reconstruction, or modification on or before November 15, 2021. Similarly, because new dry seal centrifugal compressors are those that commenced construction, reconstruction, or modification after December 6, 2022, existing dry seal centrifugal compressors are those that commenced construction, reconstruction, or modification on or before December 6, 2022.

D. How will the proposed EG OOOOc impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa?

Sources currently subject to 40 CFR part 60, subpart KKK (NSPS KKK), 40 CFR part 60 subpart OOOO (NSPS OOOO), or NSPS OOOOa would continue to comply with their respective standards until a state or Federal plan implementing EG OOOOc becomes effective. For most designated facilities, the EPA proposes to conclude that compliance with the implementing state or Federal plan that is consistent with the presumptive standards in EG OOOOc would constitute compliance with the older NSPS because the presumptive standards proposed for EG OOOOc result in the same or greater emission reductions than the current standards in the older NSPS.

In this rulemaking, the EPA is proposing standards for dry seal centrifugal compressor and intermittent bleed pneumatic controllers for the first time in NSPS OOOOb and EG OOOOc. Because these designated facilities (*i.e.,* dry seal centrifugal compressors and intermittent bleed pneumatic controllers) are not subject to regulation under a previous NSPS, they only need to comply with the state or Federal plan implementing EG OOOOc. The EPA is proposing presumptive standards for fugitive emissions at compressor stations, pneumatic pumps at natural gas processing plants, and pneumatic controllers at natural gas processing plants that are all the same or greater stringency than NSPS KKK, NSPS OOOO, and NSPS OOOOa, as applicable. Therefore, compliance with the state or Federal plan implementing EG OOOOc would satisfy compliance with the respective NSPS regulation. Additionally, the proposed presumptive standards in EG OOOOc for pneumatic pumps (excluding processing) and natural gas processing plant equipment leaks are more stringent than the standards in NSPS OOOOa for pneumatic pumps and all three NSPS for natural gas processing plant equipment leaks, and therefore compliance with the state or Federal plan implementing EG OOOOc would satisfy compliance with the respective NSPS regulation.

For wet seal centrifugal compressors, two different standards are in place for the older NSPS. NSPS KKK is an equipment standard that provides several compliance options including: (1) Operating the compressor with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; (2) equipping the compressor with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system, or that is connected by a CVS to a control device that reduces VOC emissions by 95 percent or more; or (3) equipping the compressor with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere. NSPS KKK exempts compressors from these requirements if it is either equipped with a closed vent system to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device

[11] See Document ID Nos. EPA–HQ–OAR–2021–0317–0424, EPA–HQ–OAR–2021–0317–0539, EPA–HQ–OAR–2021–0317–0579, EPA–HQ–OAR–2021–0317–0598, EPA–HQ–OAR–2021–0317–0599, EPA–HQ–OAR–2021–0317–0815, and EPA–HQ–OAR–2021–0317–0929.

that reduces VOC emissions by 95 percent, or if it is designated for no detectable emissions. NSPS OOOO and NSPS OOOOa require 95 percent reduction of emissions from each centrifugal compressor wet seal fluid degassing system. NSPS OOOO and OOOOa also allow the alternative of routing the emissions to a process. The proposed presumptive standards under EG OOOOc would be a numerical emission limit of 3 scfm, as described in IV.G. of this preamble, and includes an alternative compliance option to reduce methane emissions by 95 percent by routing to a control or process. The proposed presumptive standard of 3 scfm is less stringent than the standards in NSPS OOOO and OOOOa, and therefore, compliance with a state or Federal plan implementing EG OOOOc using the 3 scfm presumptive standard would not satisfy compliance with NSPS OOOO and NSPS OOOOa for wet seal centrifugal compressor designated facilities. However, the EPA is not aware of any wet seal centrifugal compressors subject to NSPS OOOO or NSPS OOOOa and the EPA believes that centrifugal compressors installed since those rules went into effect (August 2011 and September 2015) are utilizing dry seals rather than wet seals. For wet seal centrifugal compressors currently subject to KKK (those designated as new sources between January 1984 and August 2011), compliance with NSPS KKK would allow for compliance with the state or Federal plan implementing EG OOOOc because the zero emissions limit would also achieve the 3 scfm limit proposed in EG OOOOc. For an owner or operator who uses the alternative compliance method proposed in EG OOOOc of routing to a control or process, achieving 95 percent emissions reductions can be accomplished using the same compressor requirements as required in NSPS OOOOa. Thus, compliance with a state or Federal plan implementing EG OOOOc using the 95 percent control alternative would satisfy compliance with NSPS OOOO and NSPS OOOOa for wet seal centrifugal compressor designated facilities.

The NSPS KKK standard is more stringent than the proposed 3 scfm presumptive standard in EG OOOOc for methane emissions. Accordingly, for centrifugal compressors, NSPS KKK would still apply to compressors at natural gas processing plants for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011.

There are two different standards for reciprocating compressors in the older NSPS: (1) NSPS KKK requires the use of a seal system and includes a barrier fluid system that prevents leakage of VOC to the atmosphere for reciprocating compressors located at natural gas processing plants, and (2) NSPS OOOO and NSPS OOOOa require changing out the rod packing every 3 years or routing emissions to a control. The proposed presumptive standard for EG OOOOc is a volumetric flow rate of 2 scfm. The proposed BSER is to repair and/or replace the reciprocating compressor rod packing in order to maintain the flow rate at or below 2 scfm (based on annual monitoring and additional preventative or corrective measures) and includes an alternative compliance option to route emissions to a process, as described in IV.I. of this preamble.

The NSPS KKK standard is more stringent than the proposed 2 scfm presumptive standard in EG OOOOc for methane emissions. Accordingly, for reciprocating compressors subject to NSPS KKK, the NSPS KKK provisions would still apply to reciprocating compressors at natural gas processing plants for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011. For NSPS KKK, several provisions effectively exempt certain reciprocating compressors at natural gas processing plants from the seal system requirements, including: an exemption for reciprocating compressors in wet gas service, a requirement that reciprocating compressors must be in VOC service (*i.e.,* at least 10 percent by weight VOC in the process fluid in contact with the compressor) for standards to apply, and an exemption for reciprocating compressors designated with no detectable emissions. If a reciprocating compressor at a natural gas processing plant was constructed, reconstructed, or modified between January 20, 1984, and August 23, 2011, is exempt from the provisions of NSPS KKK due to one of these conditions, it would be subject to the requirements of the state or Federal plan implementing EG OOOOc.

As explained in section XII.E.1.d. of the November 2021 proposal [12] and section IV.I of this preamble, the EPA finds that the proposed EG OOOOc standard is more efficient at discovering and reducing any emissions that may develop than the set 3-year replacement interval from NSPS OOOO and NSPS OOOOa. Overall, the proposed presumptive standards would produce more rod packing replacements, thereby reducing more emissions compared to the 3-year interval. Therefore, the EPA is proposing that compliance with the state or Federal plan implementing EG OOOOc will satisfy compliance with the respective NSPS OOOO and OOOOa regulations for reciprocating compressor designated facilities.

The affected facility for storage vessels is defined in the NSPS OOOO and NSPS OOOOa as a single storage vessel with the potential to emit greater than 6 tons of VOC per year and the standard that applies is 95 percent emissions reduction. Under the proposed EG OOOOc, the designated facility is a tank battery with the potential to emit greater than 20 tons of methane per year with the same 95 percent emission reduction standard, as discussed in IV.J. of this preamble. Affected facilities under NSPS OOOO or OOOOa that are part of a designated facility under the EG would be required to meet the 95 percent reduction standard, and therefore would satisfy their respective NSPS requirement to do the same. Affected facilities under NSPS OOOO or OOOOa that emit 6 tpy or more of VOCs but that do not meet the potential to emit 20 tons of methane per year definition would continue to comply with the 95-percent emissions reduction standard in their respective NSPS. Scenarios regarding further physical or operational changes in NSPS OOOOb that would reclassify sources from the older NSPS and/or EG OOOOc into NSPS OOOOb are discussed in section IV.J.1.b. of this preamble.

Similarly, pneumatic controller affected facilities not located at natural gas processing plants are defined as single high-bleed controllers with a low-bleed standard under NSPS OOOO and NSPS OOOOa, while the designated facility under EG OOOOc is defined as a collection of natural gas-driven pneumatic controllers at a site with a zero emissions standard (discussed further in Section IV.D. of this preamble). The proposed zero-emissions presumptive standard in EG OOOOc is more stringent than the low-bleed standard found in the older NSPS, therefore the EPA is proposing that compliance with the state or Federal plan implementing EG OOOOc would satisfy compliance with the respective NSPS regulation for pneumatic controllers not located at a natural gas processing plant.

Lastly, standards for fugitive emissions from well sites under NSPS OOOOa require semiannual OGI monitoring on all components at the well site except for wellhead only well sites (which are not affected facilities), while the presumptive standards under the proposed EG OOOOc would require quarterly OGI monitoring at well sites

[12] 86 FR 63215 to 63220 (November 15, 2021).

with major production and processing equipment, semiannual OGI combined with quarterly AVO inspections at multi-wellhead only well sites,[13] and quarterly AVO inspections for small sites and single wellhead well sites, as described in section IV.A of this preamble. It is clear that the proposed presumptive standards for well sites with major production and processing equipment and the proposed presumptive standards for multi-wellheads only well sites are both more stringent than the semiannual OGI monitoring standard under NSPS OOOOa because one would require more frequent OGI monitoring while the other would require AVO inspections in addition to semiannual OGI monitoring; therefore, for these existing wellsites that are also subject to NSPS OOOOa, compliance with proposed presumptive standards would be deemed in compliance with the semiannual OGI monitoring standard in NSPS OOOOa. With respect to existing single wellhead only well sites and small sites that are also subject to the semiannual monitoring under NSPS OOOOa, the EPA is proposing that compliance with the proposed presumptive standards, specifically quarterly AVO, would satisfy NSPS OOOOa for the following reasons. First, as explained in more detail in section IV.A, AVO is effective, and therefore OGI is unnecessary, for detecting fugitive emissions from many of the fugitive emissions components at these sites. Second, by requiring more frequent visits to the sites, the proposed presumptive standard would allow earlier detection and repair of fugitive emissions, in particular large emissions from components such as thief hatches on uncontrolled storage vessels. In light of the above, the EPA finds that the presumptive standards under the proposed EG OOOOc would effectively address the fugitive emissions at these well sites, and that semiannual OGI monitoring would no longer be necessary for these well sites that are also subject to NSPS OOOOa. For the reasons stated above, the EPA is proposing to conclude that compliance with the state or Federal plan implementing the presumptive fugitive emissions standards in the proposed EG OOOOc may be deemed to satisfy compliance with monitoring standards (*i.e.,* semiannual monitoring using OGI) in NSPS OOOOa for all well sites.

The EPA is soliciting comment on all aspects of the proposed comparison of standards in the older NSPS to the proposed presumptive standards in EG OOOOc. Specifically, the EPA is requesting comment relevant to the comparison of stringency for compressors (both centrifugal and reciprocating) to NSPS KKK and for fugitive emissions monitoring at small well sites.

E. How does the EPA consider costs in this supplemental proposal?

In the November 2021 proposal, the EPA described the various approaches for evaluating control costs in its BSER analyses. 86 FR 63154–63157 (November 15, 2021). As described in that document, in considering the costs of the control options evaluated in this action, the EPA estimated the control costs under various approaches, including annual average cost-effectiveness and incremental cost-effectiveness of a given control. In its cost-effectiveness analyses, the EPA recognized and took into account that these multi-pollutant controls reduce both VOC and methane emissions in equal proportions, as reflected in the single-pollutant and multipollutant cost effectiveness approaches for the proposed NSPS OOOOb. The EPA also considered cost saving from the natural gas recovered instead of vented due to the proposed controls. In both the November 2021 proposal [14] and this supplemental proposal,[15] the EPA proposes to find that cost-effectiveness values up to $5,540/ton of VOC reduction are reasonable for controls that we have identified as BSER and within the range of what the EPA has historically considered to represent cost effective controls for the reduction of VOC emissions. Similarly, for methane, the EPA finds the cost-effectiveness values up to $1,970/ton of methane reduction to be reasonable for controls that we have identified as BSER in both the November 2021 proposal and this supplemental proposal, well below the $2,185/ton [16] of methane reduction that EPA has previously found to be reasonable for the industry.

For this supplemental proposal, we also updated the two additional analyses that the EPA performed for the November 2021 proposal to further inform our determination of whether the cost of control of the collection of proposed standards would be reasonable, similar to compliance cost analyses we have completed for other NSPS.[17] The two additional analyses include: (1) A comparison of the capital costs incurred by compliance with the proposed rules to the industry's estimated new annual capital expenditures, and (2) a comparison of the annualized costs that would be incurred by compliance with the proposed standards to the industry's estimated annual revenues. In this section, the EPA provides updated information regarding these cost analyses based on the proposed standards described in this notice. See 86 FR 63156 (November 15, 2021) for additional discussion on these two analyses.

First, for the capital expenditures analysis, the EPA divided the nationwide capital expenditures projected to be spent to comply with the proposed standards by an estimate of the total sector-level new capital expenditures for a representative year to determine the percentage that the nationwide capital cost requirements under the proposal represent of the total capital expenditures by the sector. We combine the compliance-related capital costs under the proposed standards for the NSPS and for the presumptive standards in the proposed EG to analyze the potential aggregate impact of the proposal. The EAV of the projected compliance-related capital expenditures over the 2023 to 2035 period is projected to be about $1.4 billion in 2019 dollars. We obtained new capital expenditure data for relevant NAICS codes for 2019 from the U.S. Census 2020 Annual Capital Expenditures Survey.[18] While Census data on capital expenditures are available for 2020, these figures were heavily influenced by COVID–19-related impacts such that 2020 does is not an appropriate representative year to use in this analysis. According to these data, new capital expenditures for the sector in 2019 were about $156 billion in 2019

[13] Because of a difference in the definition of a wellhead only well site in NSPS OOOOa and the proposed EG OOOOc, some single and multi-wellhead only well sites could be subject to the semiannual OGI monitoring under NSPS OOOOa.

[14] 86 FR 63155 (November 15, 2021).

[15] See November 2021 TSD at Document ID No. EPA–HQ–OAR–2021–0317–0166 and Supplemental TSD for this action located at Docket ID No. EPA–HQ–OAR–2021–0317.

[16] 80 FR 56627 (June 6, 2016). See also, ''Background Technical Support Document for the New Source Performance Standards 40 CFR part 60 subpart OOOOa (May 2016)'', at page 93, Table 6–7 located at Document ID No. EPA–HQ–OAR–2010–0505–7631.

[17] For example, see our compliance cost analysis in ''Regulatory Impact Analysis (RIA) for Residential Wood Heaters NSPS Revision. Final Report.'' U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. EPA–452/R–15–001, February 2015.

[18] U.S. Census Bureau, 2020 Annual Capital Expenditures Survey, Table 4b. Capital Expenditures for Structures and Equipment for Companies with Employees by Industry: 2019 Revised, *https://www.census.gov/data/tables/2020/econ/aces/2020-aces-summary.html,* accessed 7/12/2022.

dollars.[19] Note that new capital expenditures for pipeline transportation of natural gas (NAICS 4862) includes only expenditures on structures as data on expenditures on equipment data are withheld to avoid disclosing data for individual enterprises. As a result, the capital expenditures used here represent an underestimate of the sector's expenditures. Comparing the EAV of the projected compliance-related capital expenditures under the proposal with the 2019 total sector-level new capital expenditures yields a percentage of about 0.9 percent, which is well below the percentage increase previously upheld by the courts.

Second, for the comparison of compliance costs to revenues, we use the EAV of the projected compliance costs without and with projected revenues from product recovery under the proposal for the 2023 to 2035 period then divided the nationwide annualized costs by the annual revenues for the appropriate NAICS code(s) for a representative year to determine the percentage that the nationwide annualized costs represent of annual revenues. Like we do for capital expenditures, we combine the costs projected to be expended to comply with the standards for NSPS and the presumptive standards in the proposed EG to analyze the potential aggregate impact of the proposal. The EAV of the associated increase in compliance cost over the 2023 to 2035 period is projected to be about $1.7 billion without revenues from product recovery and about $1.2 billion with revenues from product recovery (in 2019 dollars). Revenue data for relevant NAICS codes were obtained from the U.S. Census 2017 County Business Patterns and Economic Census, the most recent revenue figures available.[20] According to these data, 2017 receipts for the sector were about $358 billion in 2019 dollars. Comparing the EAV of the projected compliance costs under the proposal with the sector-level receipts figure yields a percentage of about 0.5 percent without revenues from product recovery and about 0.4 percent with revenues from product recovery. More data and analysis supporting the comparison of capital expenditures and annualized costs projected to be incurred under the rule and the sector-level capital expenditures and receipts is presented in the TSD for this action, which is in the public docket.

In considering the costs of the control options evaluated in this action, the EPA estimated the control costs under various approaches, including annual average cost-effectiveness and incremental cost-effectiveness of a given control. In its cost-effectiveness analyses, the EPA recognized and took into account that these multi-pollutant controls reduce both VOC and methane emissions in equal proportions, as reflected in the single-pollutant and multipollutant cost effectiveness approaches for the proposed NSPS OOOOb. The EPA also considered cost saving from the natural gas recovered instead of vented due to the proposed controls. Based on all of the considerations described, the EPA concludes that the costs of the controls that serve as the basis of the standards proposed in this action are reasonable. The EPA solicits comment on its approaches for considering control costs, as well as the resulting analyses and conclusions.

F. Legal Basis for Rulemaking Scope

In the November 2021 proposal, the EPA described the regulatory history of its authority to regulate methane emissions from the oil and gas source category under CAA section 111. The EPA explained that the 2016 Rule, 81 FR 35823 (June 3, 2016), established the agency's authority to regulate these methane emissions; the 2020 Policy Rule, 85 FR 57018 (September 14, 2020) had rescinded certain parts of the 2016 Rule, including its authorization to regulate methane; and a joint resolution under the Congressional Review Act (CRA), signed into law by President Biden on June 30, 2021, had rescinded the 2020 Policy Rule, and thereby reinstated the 2016 Rule's authorization to regulate methane. 86 FR 63135–36 (November 15, 2021).

In describing this history, the EPA noted that in the 2016 Rule, in response to comments, the EPA had explained that once it had listed a source category for regulation under section 111(b)(1)(A), it was not required to make, as a predicate to regulating GHG emissions from the source category, an additional pollutant-specific finding that those GHG emissions contribute significantly to dangerous air pollution (termed, a pollutant-specific significant contribution finding). However, in the alternative, the 2016 Rule did make such a finding, relying on information concerning the large amounts of methane emissions from the source category. 86 FR 63135 (November 15, 2021) (citing 81 FR 35843; June 3, 2016). The November 2021 proposal further noted that in the legislative history of the CRA resolution, Congress made clear its intent that section 111 did not require or authorize a pollutant-specific significant contribution finding, and the EPA confirmed that it agreed with that interpretation. 86 FR 63148 (November 15, 2021).

Some commenters on the November 2021 proposal reiterated the argument that the EPA is required to make a pollutant-specific significant contribution finding for GHG emissions from the oil and gas source category and stated that in order to make such a finding, the EPA must identify a standard or criteria for when a contribution is significant.[21] We may respond further to these comments in the final rule, but the November 2021 proposal notes that the legislative history of the CRA joint resolution rejected the position that a standard or criteria is necessary for determining significance, and explained, ''It is fully appropriate for EPA to exercise its discretion to employ a facts-and-circumstances approach, particularly in light of the wide range of source categories and the air pollutants they emit that EPA must regulate under section 111.'' 86 FR 63151 (November 15, 2021) (quoting House Report at 11). That continues to be the EPA's view and is consistent with decades of practice under section 111. The EPA has listed dozens of source categories, beginning in 1971,[22] in many cases on the basis of multiple pollutants emitted by the particular source category,[23] and has never identified a standard or criteria for determining significance.

If the EPA were required to develop a standard or criteria to determine significance, any reasonable set of criteria would necessarily focus on the amount of emissions from the source category and the harmfulness of the pollutant emitted. In the case of the oil and gas source category, the ''massive quantities of methane emissions''

[19] The total capital expenditures for the same NAICS codes during COVID 19-impacted 2020 were about $90 billion.

[20] 2017 County Business Patterns and Economic Census. The Number of Firms and Establishments, Employment, Annual Payroll, and Receipts by Industry and Enterprise Receipts Size: 2017, *https://www.census.gov/programs-surveys/susb/data/tables.2017.html,* accessed September 4. 2021. Note receipts data are available only for Economic Census years (years ending in 2 and 7) so 2017 data remains the most recent data available.

[21] Comments of Permian Basin Petroleum Ass'n, Document ID No. EPA–HQ–OAR–2021–0317–0793 at 3–4 (citing 85 FR 57018, 57038 (September 14, 2020).

[22] List of Categories of Stationary Sources, 36 FR 5931 (March 31, 1971); *see* 40 CFR part 60.

[23] For example, when it listed ''stationary gas turbines'' as a source category, EPA considered emissions of particulates, nitrogen oxides, sulfur dioxide, carbon monoxide, and hydrocarbons. Addition to the List of Categories of Stationary Sources, 42 FR 53657 (October 3, 1977); Standards of Performance for New Stationary Sources: Proposed rule, 42 FR 53782, 53783 (October 3, 1977).

contributed by the sector to the levels of well-mixed GHG in the atmosphere, as described in the November 2021 proposal, 86 FR 63148 (November 15, 2021), coupled with the potency of methane (with a global warming potential (GWP) of almost 30 or more than 80, depending on the time period of the impacts, 86 FR 63130; November 15, 2021), demonstrate that the source category's GHG emissions would be significant under any rational criteria-based approach. More specifically, as the EPA stated in the November 2021 proposal, as illustrated by the domestic and global GHGs comparison data summarized in that notice, the collective GHG emissions from the Crude Oil and Natural Gas source category are significant, whether the comparison is domestic (where this sector is the largest source of methane emissions, accounting for 28 percent of U.S. methane and 3 percent of total U.S. emissions of all GHGs), global (where this sector, accounting for 0.4 percent of all global GHG emissions, emits more than the total national emissions of over 160 countries, and combined emissions of over 60 countries), or when both the domestic and global GHG emissions comparisons are viewed in combination. See 86 FR 63131 (November 15, 2021).

The large quantity of methane emitted by the oil and gas source category is brought into sharp relief by the fact that, as the November 2021 proposal further stated, no single GHG source category dominates on the global scale. While the Crude Oil and Natural Gas source category, like many (if not all) individual GHG source categories, could appear small in comparison to total emissions, in fact, it is a very important contributor in terms of both absolute emissions, and in comparison, to other source categories globally or within the U.S. See 86 FR 63131 (November 15, 2021).

Importantly, the oil and gas source category is the largest emitter of methane of any source category in the United States. 86 FR 63129 (November 15, 2021). As described in the November 2021 proposal, methane is a potent greenhouse gas; over a 100-year timeframe, it is nearly 30 times more powerful at trapping climate warming heat than CO_2, and over a 20-year timeframe, it is 83 times more powerful. Because methane is a powerful greenhouse gas and is emitted in large quantities, reductions in methane emissions provide a significant benefit in reducing near-term warming. Indeed, one third of the warming due to GHGs that we are experiencing today is due to human emissions of methane. See 86 FR 63129 (November 15, 2021).

The large amounts of methane emissions from the oil and gas source category in relation to other domestic and global sources of methane, coupled with the harmfulness of methane, should be considered more than sufficient to satisfy any criterion or standard for evaluating significant contribution. In particular, in the context of a problem like climate change that is caused by the collective contribution of many different sources, the fact that the oil and gas source category has the largest amount of methane emissions in the United States confirms that those emissions would meet a criterion or standard for significance.[24]

G. Inflation Reduction Act

The Inflation Reduction Act (IRA) was signed into law on August 16, 2022. Section 60113 of the IRA amended the CAA by adding section 136, ''Methane Emissions and Waste Reduction Incentive Program for Petroleum and Natural Gas Systems.'' Under this new section of the CAA, subsection 136(c), ''Waste Emission Charge,'' requires the Administrator to ''impose and collect a charge on methane emissions that exceed an applicable waste emissions threshold under subsection (f) from an owner or operator of an applicable facility that reports more than 25,000 metric tons of carbon dioxide equivalent of greenhouse gases emitted per year pursuant to subpart W of part 98 of title 40, Code of Federal Regulations (40 CFR part 98), regardless of the reporting threshold under that subpart.'' An ''applicable facility'' is defined under CAA section 136(d) by reference to specific industry segments as defined in the Greenhouse Gas Reporting Program (GHGRP) petroleum and natural gas systems source category (40 CFR part 98, subpart W, also referred to as ''GHGRP subpart W''). Pursuant to CAA section 136(g), the charge is to be imposed and collected beginning with respect to emissions reported for calendar year 2024 and for each year thereafter.

CAA section 136(f) identifies several circumstances under which the charges shall not be imposed on an owner or operator of an affected facility. In particular, CAA section 136(f)(6)(A) states that ''charges shall not be imposed pursuant to subsection (c) on an applicable facility that is subject to and in compliance with methane emissions requirements pursuant to subsections (b) and (d) of section 111 upon a determination by the Administrator that:

(i) Methane emissions standards and plans pursuant to subsections (b) and (d) of section 111 have been approved and are in effect in all States with respect to the applicable facilities; and

(ii) compliance with the requirements described in clause (i) will result in equivalent or greater emissions reductions as would be achieved by the proposed rule of the Administrator entitled '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 (November 15, 2021)), if such rule had been finalized and implemented.''

Per section 136(c)(6)(B) ''if the conditions in clause (i) or (ii) of subparagraph (A) cease to apply after the Administrator has made the determination in that subparagraph, the applicable facility will again be subject to the charge under subsection (c) beginning in the first calendar year in which the conditions in either clause (i) or (ii) of that subparagraph are no longer met.''

The EPA intends to take one or more separate actions in the future to implement the Methane Emissions and Waste Reduction Incentive Program, including revisions to certain requirements of GHGRP subpart W, and will provide an opportunity for public comment on the implementation of the Methane Emissions and Waste Reduction Incentive Program in those actions. Accordingly, the EPA considers the implementation of the Methane Emissions and Waste Reduction Incentive Program to be outside the scope of this supplemental proposed rule. However, the EPA is requesting comments on the criteria and approaches that the Administrator

[24] The EPA acknowledges that the collective nature of the climate change problem means it will likely also be appropriate to regulate other source categories of methane emissions that are not necessarily as large as the oil and gas source category, *cf. EPA* v. *EME Homer City,* 572 U.S. 489, 514 (2014) (affirming framework to address ''the collective and interwoven contributions of multiple upwind States'' to ozone nonattainment), as indicated by the fact that EPA has long regulated landfill gas, which consists of methane in 50 percent part. ''Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills; Final Rule,'' 81 FR 59276, 59281 (August 29, 2016). But this does not mean that it would be appropriate to regulate *all* other types of sources, even ones with few emissions. In the past, the EPA has declined to regulate air pollutants emitted from source categories in quantities too small to be worrisome and because regulation would have produced little environmental benefit. *See Nat'l Lime Ass'n.* v. *EPA,* 627 F.2d 416, 426 & n.27 (D.C. Cir. 1980) (small amounts of emissions of nitrogen oxides and carbon monoxide from lime kilns was a key factor in EPA decision not to promulgate new source performance standards for those pollutants; citing Standards of Performance for New Stationary Sources Lime Manufacturing Plants—Proposed Rule, 42 FR 22506, 22507 (May 3, 1977)).

should consider in making the CAA section 136(f)(6)(A)(ii) determination (''IRA equivalence determination'') because the EPA expects that the public and regulated industry will be interested in how the scope of the final oil and gas standards and emission guidelines may influence the applicability of the statutory exemption.

With respect to CAA section 136(f)(6)(A)(ii), the Administrator must determine that the methane emission standards in effect pursuant to CAA sections 111(b) and (d) ''will result in equivalent or greater emissions reductions as would be achieved'' by the EPA's November 2021 proposed rule. As a general matter, the EPA believes that the changes being proposed in today's action do not reduce expected methane emission reductions relative to the November 2021 proposal. Instead, the EPA anticipates that most, if not all, of the proposed changes contained in this supplemental proposal would likely lead to greater methane emissions reductions when fully implemented. For this reason, the Agency further anticipates that promulgation of Federal and state standards consistent with this supplemental proposal would result in methane emissions reductions at least as great as the November 2021 proposal. However, at this point, the EPA's analysis is purely qualitative. The EPA does not believe that it is appropriate to quantitatively compare the emission reductions from the November 2021 proposal and this supplemental proposal because, as is discussed in section 1.3 of the RIA, the analysis of this supplemental proposal includes key updates to assumptions and methodologies that impact both the baseline and policy scenarios. As such, the estimated impacts presented in the RIA of this supplemental proposal are not directly comparable to corresponding estimates presented in the RIA of the November 2021 proposal.

Moreover, the statutory language in CAA section 136(f)(6)(A)(ii) does not indicate how the EPA should conduct this equivalency evaluation and what factors should influence how the EPA conducts the comparison. Because of this ambiguity in the statutory language, the EPA is requesting comments on how to best conduct this evaluation and on factors and assumptions the EPA should consider in conducting such an evaluation.

First, the EPA seeks comments on temporal elements of the evaluation. The EPA believes that the appropriate temporal comparison should be based on when requirements are fully implemented by the sources (*i.e.,* if a state phases in installation of zero-emitting pneumatic controllers over more than one year, the comparison should be made at the point that the emission guidelines require full use of zero-emitting controllers). The EPA seeks comment on this approach versus an alternative such as making a multi-year comparison beginning with the effective date of the rule. In either case, as discussed below, such a determination could be made prospectively based either on the rule finalized by the EPA or when state plans have been approved. As discussed in section V.D. of the supplemental proposal, the EPA is proposing to require the submission of state plans under EG OOOOc within 18 months after publication of the final EG. In addition, the EPA is proposing to require that state plans impose a compliance timeline on designated facilities to require final compliance with the standards of performance as expeditiously as practicable, but no later than 36 months following the state plan submittal deadline.

Second, the EPA seeks comments on geographical elements of the evaluation. Per the statutory language in CAA section 136(f)(6)(A)(i), the EPA's evaluation is to be done with respect to all states. The EPA requests comments on whether we should consider making a national evaluation of equivalency or whether we should consider a state-by-state evaluation instead. Under a national evaluation, the EPA envisions conducting an assessment of the reductions achieved across all states and then evaluating those reductions collectively against the collective reductions anticipated from implementation of the November 2021 proposal. Under a state-by-state evaluation, the EPA envisions needing to analyze whether every state is achieving equivalent or greater reductions than that state would have achieved under the November 2021 proposal.

Third, the EPA requests comments on whether the EPA should make the evaluation and the IRA equivalency determination in advance of states having submitted fully approvable plans or instead make the evaluation and IRA equivalency determination at a later date once the standards of performance pursuant to CAA section 111(b) and 111(d) are fully promulgated (*e.g.,* the EPA has approved state plans and/or developed a Federal Plan). In particular, the EPA request comments on whether the EPA's analysis should compare the November 2021 EG proposal and final EG OOOOc by assuming designated facilities would be subject to their corresponding EG presumptive standards once state plans are implemented, or whether we should compare the November 2021 EG proposal to the actual state plans that are approved. As to the latter approach, the EPA seeks comments on how a state's invocation of RULOF to apply a less stringent standard to a designated facility might affect the equivalency evaluation and IRA equivalency determination. In establishing standards of performance for individual sources, CAA section 111(d) and the EPA's regulations provide that states may invoke RULOF for the application of less stringent standards provided they meet the certain requirements established in the EPA's regulations and the EG (see section V.B.3 below). As a result, it is possible that those state plans (individually or collectively) may not result in equivalent or greater emissions reductions as would be achieved by full implementation of the presumptive standards in the November 2021 proposal, unless the state plans require other sources to overperform to compensate for the less stringent RULOF standards or the EPA's geographical evaluation is national in scope and national emissions result in equivalent or greater emissions reductions, even taking into account RULOF. The EPA requests comments on whether and how to account for the potential application of RULOF in state plans in the IRA equivalency determination and whether it would be appropriate to conduct any evaluation without considering the application of RULOF.

The EPA notes that nothing in the new CAA section 136 supersedes the EPA's statutory obligations under CAA section 111. The Methane Emission and Waste Reduction Incentive Program does not supersede the EPA's statutory obligation, under CAA section 111, to regulate methane emissions from the Crude Oil and Natural Gas source category. The EPA first regulated GHG emissions from new, reconstructed, and modified sources through limitations on methane emissions in its 2016 NSPS OOOOa rulemaking. Therefore, the Agency is obligated to review those standards at least every 8 years pursuant to CAA section 111(b)(1)(B). Moreover, CAA section 111(d) requires the EPA to establish emission guidelines to regulate methane emissions from any existing sources in the sector to which a standard of performance would apply if it were a new source. Although CAA section 136(f)(6) provides that facilities may be exempted from the obligation to pay methane charges if they are compliant with applicable CAA section 111(b) and (d) standards meeting certain criteria after the Administrator makes the IRA equivalency determination in CAA section 136(f)(6)(A), CAA section 136 does not provide that the Methane Emission and Waste Reduction Incentive Program may, in the alternative, serve as a compliance alternative for any applicable CAA section 111 standards for methane. Accordingly, affected facilities subject to the final NSPS OOOOb must continue to comply with the final standards of performance regardless of whether they are subject to or exempted from the waste emissions charge. Likewise, designated facilities subject to standards of performance pursuant to either an approved state plan or a federal plan according to the requirements in CAA section 111(d) and the final EG OOOOc must continue to comply with those standards regardless of whether they are subject to or exempted from the waste emissions charge. The EPA acknowledges the potential interplay between the provisions in this proposed rule and the Methane Emissions and Waste Reduction Incentive Program and invites comment on approaches for examining the economic impacts of these programs individually and collectively.

IV. Summary and Rationale for Changes to the Proposed NSPS OOOOb and EG OOOOc

A. Fugitive Emissions From Well Sites, Centralized Production Facilities, and Compressor Stations

As discussed in section XI.A of the November 2021 proposal preamble (86 FR 63169; November 15, 2021), fugitive emissions are unintended emissions that can occur from a range of components at any time. The magnitude of these emissions can also vary widely. The EPA has historically addressed fugitive emissions from the Crude Oil and Natural Gas source category through ground-based component level monitoring using OGI or Method 21 of appendix A–7 to 40 CFR part 60 (EPA Method 21).

This section presents a summary of the November 2021 proposal, the rationales for making certain changes to the proposed standards and requirements, and the resulting NSPS standards and EG presumptive standards the EPA is proposing via this supplemental proposal for fugitive emissions from well sites and compressor stations. For proposed standards and requirements that have not changed since the November 2021 proposal, their supporting rationales are not reiterated in this supplemental proposal. Rationale included in the November 2021 proposal for these standards and requirements can be found in that proposal preamble (86 FR 63110; November 15, 2021) and in the technical support document (TSD) for the November 2021 proposal located at (EPA–HQ–OAR–2017–0166).

1. Fugitive Emissions at Well Sites and Centralized Production Facilities

a. NSPS OOOOb

i. Summary of November 2021 Proposal

Affected Facility. The November 2021 proposal defined the affected facility as the collection of fugitive emissions components located at well sites and centralized production facilities. The November 2021 proposal excluded ‘‘wellhead only well sites’’ as affected facilities under NSPS OOOOb, which were defined as well sites with one or more wellheads and no major production and processing equipment. Major production and processing equipment was defined as reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels.

Definition of fugitive emissions component. The November 2021 proposal included an expanded definition of fugitive emissions component that was intended to capture the known sources of large emission events. Specifically, the proposed definition in the November 2021 proposal defined a fugitive emissions component as ‘‘any component that has the potential to emit fugitive emissions of methane and VOC at a well site or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, all covers and CVS, all thief hatches or other openings on a controlled storage vessel, compressors, instruments, meters, natural gas-driven pneumatic controllers, or natural gas-driven pneumatic pumps. However, natural gas discharged from natural gas-driven pneumatic controllers or natural gas-driven pumps are not considered fugitive emissions if the device is operating properly and in accordance with manufacturers specifications. Control devices, including flares, with emissions resulting from the device operating in a manner that is not in full compliance with any Federal rule, state rule, or permit, are also considered fugitive emissions components.’’ (86 FR 63170; November 15, 2021).

Summary of November 2021 Proposal BSER Analysis. The methodology used to determine BSER for the November 2021 proposal was presented in the section X.II.A of that proposal preamble (86 FR 63186; November 15, 2021). In the November 2021 proposal, the EPA proposed new work practice standards for the collection of fugitive emissions components located at well sites. The EPA proposed that well sites with total site-level baseline methane emissions less than 3 tpy would demonstrate, based on a one-time site-specific survey, that actual emissions are reflected in the baseline methane emissions calculation. For well sites with total site-level baseline methane emissions of 3 tpy or greater, the EPA proposed quarterly OGI or EPA Method 21 monitoring. The EPA also co-proposed an alternative set of work practice standards: for well sites with total site-level baseline methane emissions of 3 tpy or greater and less than 8 tpy semiannual OGI or EPA Method 21 monitoring would apply; and for well sites with total site-level baseline methane emissions of 8 tpy or greater, quarterly OGI or EPA Method 21 monitoring would apply. For sites using OGI to detect fugitive emissions under any of these proposed work practice standards, the EPA proposed that surveys would be conducted according to the procedures proposed as appendix K. See section VI of this preamble for more information regarding appendix K.

ii. Changes to Proposal and Rationale

The EPA is proposing certain changes to the November 2021 proposal standards for NSPS OOOOb. Specifically, the EPA is proposing: (1) To require OGI monitoring for well sites and centralized production facilities following the monitoring plan required in proposed 40 CFR 60.5397b instead of requiring the procedures being proposed in appendix K for these sites; (2) to expand the affected facility definition to include wellhead only well sites, which were previously exempt, and add a subcategory for small well sites; (3) to revise the definition of fugitive emissions component; (4) to require periodic AVO or other detection methods for all well sites and centralized production facilities (except those located on the Alaskan North Slope) at frequencies based on the subcategory of well site; (5) to require periodic OGI fugitive emissions monitoring based on the number and type of equipment located at the well site, in lieu of the baseline emissions calculations required in the November 2021 proposal; and (6) to include requirements for well closures that would indicate when fugitive emissions monitoring could stop.

Appendix K. The EPA is not including a requirement to conduct OGI monitoring according to the proposed appendix K for well sites or centralized production facilities, as was proposed in the November 2021 proposal. Instead, the EPA is proposing to require OGI surveys following the procedures specified in the proposed regulatory text for NSPS OOOOb (at 40 CFR 60.5397b) or according to EPA Method 21. The EPA received extensive comments [25] from oil and gas operators and other groups on the numerous complexities associated with following the proposed appendix K, especially considering the remoteness and size of many of these sites. In addition, commenters pointed out that OGI has always been the BSER for fugitive monitoring at well sites and was never designed as a replacement for EPA Method 21, while appendix K was designed for use at more complex processing facilities that have historically been subject to monitoring following EPA Method 21. The EPA agrees with the commenters and is proposing requirements within NSPS OOOOb at 40 CFR 60.5397b in lieu of the procedures in appendix K for fugitive emissions monitoring at well sites or centralized production facilities. See section VI of this preamble for additional information on what the EPA is proposing for appendix K related to other sources (*e.g.,* natural gas processing plants).

Affected facility and subcategorization of well sites. The EPA is proposing to expand the affected facility definition to include the collection of fugitive emissions components at all well sites, including the previously excluded wellhead only well sites. Various studies, including a recent U.S. Department of Energy funded study on quantifying methane emissions from marginal wells,[26] demonstrate that fugitive emissions do occur from wellheads, and in some cases can be significant. As discussed in detail later in this section, the EPA evaluated emissions reductions resulting from the implementation of a fugitive emissions monitoring and repair program for a range of well site and centralized production facility configurations, ranging from the single wellhead only well site, to sites with specific major production and processing equipment present. While different types of monitoring techniques were found appropriate at the various site configurations evaluated, the EPA did not find support for an exemption of any site from the standards. Therefore, the EPA is proposing to define the affected facility as the collection of fugitive emissions components located at a well site or centralized production facility with no exemptions.

Further, the EPA is proposing monitoring and repair programs specific to four distinct subcategories of well sites: (1) Single wellhead only well sites,[27] (2) wellhead only well sites with two or more wellheads, (3) well sites and centralized production facilities [28] with major production and processing equipment, and (4) small well sites. The third subcategory includes well sites and centralized production facilities that have: (1) One or more controlled storage vessels, (2) one or more control devices, (3) one or more natural gas-driven pneumatic controllers or pumps, or (4) two or more other major production and processing equipment. The fourth subcategory, small well sites, are single wellhead well sites that do not contain any controlled storage vessels, control devices, pneumatic controller affected facilities, or pneumatic pump affected facilities, and include only one other piece of major production and processing equipment. Major production and processing equipment that would be allowed at a small well site would include a single separator, glycol dehydrator, centrifugal and reciprocating compressor,[29] heater/treater, and storage vessel that is not controlled. By this definition, a small well site could only potentially contain a well affected facility (for well completion operations or gas well liquids unloading operations that do not utilize a CVS to route emissions to a control device) and a fugitive emissions components affected facility. No other affected facilities, including those utilizing CVS (such as pneumatic pumps routing to control) can be present for a well site to meet the definition of a small well site. The proposed monitoring requirements for each of these subcategories is described in more detail later in this section.

Definition of fugitive emissions component. The EPA is proposing specific revisions to the definition of fugitive emissions component that was included in the November 2021 proposal. First, the EPA is proposing to add yard piping as one of the specifically enumerated components in the definition of a fugitive emissions component. While not common, pipes can experience cracks or holes, which can lead to fugitive emissions. The EPA is proposing to include yard piping in the definition of fugitive emissions component to ensure that when fugitive emissions are found from the pipe itself the necessary repairs are completed accordingly.

Second, the EPA is correcting an error made in the November 2021 proposal. The EPA had proposed that all thief hatches and other openings on all controlled storage vessels would be considered fugitive emissions components. This definition inadvertently included storage vessels that would already be subject to control as storage vessel affected facilities/designated facilities, including regular inspections of thief hatches and other sources of fugitive emissions that are separately required as part of the proposed standards for storage vessel affected facilities/designated facilities (see section IV.I of this preamble). The EPA is correcting that error in this supplemental proposal to avoid establishing redundant or duplicative requirements. Instead, the EPA is defining fugitive emissions components to include all thief hatches and other openings on storage vessels that are constructed, reconstructed, or modified after November 15, 2021, and not also subject to control as storage vessel affected facilities. This would include thief hatches and other openings on both uncontrolled storage vessels and storage vessels that are controlled for other purposes but not subject to NSPS OOOOb control requirements because fugitive emissions can occur from these components.

Third, the EPA is not defining control devices as fugitive emissions

[25] See Document ID Nos. EPA–HQ–OAR–2021–0317–0579, EPA–HQ–OAR–2021–0317–0743, EPA–HQ–OAR–2021–0317–0764, EPA–HQ–OAR–2021–0317–0777, EPA–HQ–OAR–2021–0317–0782, EPA–HQ–OAR–2021–0317–0786, EPA–HQ–OAR–2021–0317–0793, EPA–HQ–OAR–2021–0317–0802, EPA–HQ–OAR–2021–0317–0807, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0810, EPA–HQ–OAR–2021–0317–0814, EPA–HQ–OAR–2021–0317–0817, EPA–HQ–OAR–2021–0317–0820, EPA–HQ–OAR–2021–0317–0831, EPA–HQ–OAR–2021–0317–0834, and EPA–HQ–OAR–2021–0317–0938.

[26] Bowers, Richard L. *Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells.* United States. *https://doi.org/10.2172/1865859.*

[27] The EPA defines a wellhead only well site as a well site that contains one or more wellheads and no major production and processing equipment.

[28] Centralized production facilities include one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations.

[29] The EPA is proposing to exclude compressors that are located at well sites from the definition of a centrifugal affected facility and reciprocating affected facility, consistent with the November 2021 proposal. See 86 FR 63180 (November 15, 2021).

components. One commenter stated that emissions resulting from noncompliance with control device requirements should not also be defined as fugitive emissions.[30] This commenter opined that since control devices are inherently designed to have emissions, even when well operated, it should be expected that some amount of methane and VOC would be detected during an OGI survey for fugitive emissions. The EPA agrees that control devices should not be treated as fugitive emissions components and is therefore revising the definition in this proposal to not include those devices. Further, as discussed in more detail in section IV.H of this preamble, the EPA anticipates that control devices are used to meet at least one of the emissions standards in the proposed rules, and as such, they would be subject to the control device requirements in NSPS OOOOb or EG OOOOc. See section IV.H of this preamble for additional discussion on proposed requirements specific to control devices.

Finally, the EPA is not maintaining the inclusion of natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps as fugitive emissions components. These devices are both separate affected facilities with separate standards identified as BSER.[31] See sections IV.D and IV.E of this preamble for information about the proposed BSER for natural gas-driven pneumatic controllers and natural gas-driven pneumatic pumps, respectively.

The EPA is proposing specific requirements throughout this supplemental proposal that will address emissions from controlled storage vessels and natural gas-driven pneumatic controllers and pumps, including requirements for quarterly OGI monitoring. These monitoring requirements provide compliance assurance that the proposed performance standards for these sources are being complied with and obviate any need to include these sources in the definition of a fugitive emissions component. For control devices, the EPA is proposing additional initial and continuous compliance measures to ensure the required emissions reductions are being achieved. See sections IV.D for discussion on pneumatic controllers, IV.E for discussion on pneumatic pumps, IV.H for discussion on combustion control devices, IV.J for discussion on storage vessels, and IV.K for discussion on covers and CVS.[32]

Comments received on monitoring requirements. As discussed in the November 2021 proposal, the EPA proposed to require fugitive emissions monitoring using OGI based on the site-level methane baseline emissions, as determined, in part, through equipment and component count emissions factors. Further, the EPA solicited comment on adding routine AVO monitoring in addition to periodic OGI monitoring to help identify potential large emission events. Several comments, mostly from small businesses, were received regarding the use of AVO inspections because these are low cost and simple inspections that would identify indications of leaks, such as open thief hatches on storage vessels. These comments ranged from requiring monthly to annual AVO inspections in lieu of OGI monitoring, to requests to minimize the complexity of any associated recordkeeping and reporting requirements should the EPA require this type of inspection.[33]

The EPA received substantive comments from several commenters on the November 2021 proposal regarding OGI monitoring arguing that the proposed requirements for well sites were unreasonable and would be difficult to implement, especially for well sites with total site-level baseline methane emissions less than 3 tpy. Specifically, these commenters[34] asserted that there would be challenges around calculating the site-level baseline emissions and that this task would be burdensome, while other commenters[35] asserted the calculations would result in no regular monitoring at sites that have leak-prone equipment. Further, commenters noted that it would be difficult to verify the emissions calculations, which could result in compliance and/or enforcement challenges. According to industry commenters,[36] the requirement to repeat the calculation when equipment is added or removed from the site would be especially burdensome. One of the commenters further stated this requirement would force owners and operators to constantly maintain an inventory of equipment, with some operators carrying this burden for hundreds to thousands of sites.[37] Moreover, the commenter indicated that the EPA has not explained the need for the proposed recalculation of site-level methane emissions based on equipment changes and how this would have an environmental benefit. Another commenter argued that the EPA did not properly explain the basis for the emissions thresholds and disagreed with the components and equipment included in the calculation, as well as the use of the GHGRP emissions factors.[38]

In response to the proposed site-specific survey to demonstrate that actual emissions are reflected in the baseline emissions calculation, some commenters asserted that well sites with emissions less than 3 tpy should not be exempt from regular monitoring. According to commenters, even small sites can have leaks with significant emissions.[39] For this reason, the commenters made the case that regular monitoring should be required for all sites. Some commenters also expressed that the requirement to calculate site-level methane baseline emissions and conduct an initial survey was confusing. As explained by one commenter, ''[the] EPA states well sites with site-level baseline methane emissions [less than] 3 tpy are not required to conduct OGI monitoring.''[40] See 86 FR 63171 (November 15, 2021); however, since the EPA also proposed that well sites would be required to perform a survey to confirm that the actual emissions are less than 3 tpy, the commenter viewed this as a contradiction within the rule, thus making it unclear what the EPA was proposing.

One commenter indicated that monitoring should also be required for

[30] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

[31] As explained in sections IV.D for pneumatic controllers and IV.E for pneumatic pumps, only natural gas-driven pneumatic controllers and pumps are defined as affected facilities. For a controller or pump to not be an affected facility, it would need to be electric or solar, which would not have the potential to emit methane or VOC emissions. Therefore, the EPA does not consider pneumatic controllers or pneumatic pumps part of the fugitive emissions components when they are not affected facilities as controllers or pumps.

[32] The EPA notes quarterly OGI monitoring will also be performed to demonstrate compliance with specific standards for controlled storage vessels, natural gas-driven pneumatic controllers, natural gas-driven pneumatic pumps, and CVS associated with any affected facilities at well sites. This quarterly OGI monitoring would take place during the same quarterly OGI monitoring of the fugitive emissions components affected facility located at the same well site.

[33] See Document ID Nos. EPA–HQ–OAR–2021–0317–0585, EPA–HQ–OAR–2021–0317–0814, EPA–HQ–OAR–2021–0317–0822, EPA–HQ–OAR–2021–0317–0929, and EPA–HQ–OAR–2021–0317–0935.

[34] See Document ID Nos. EPA–HQ–OAR–2021–0317–0808 and EPA–HQ–OAR–2021–0317–0814.

[35] See Document ID No. EPA–HQ–OAR–2021–0317–0844.

[36] See Document ID Nos. EPA–HQ–OAR–2021–0317–0808 and EPA–HQ–OAR–2021–0317–0814.

[37] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

[38] See Document ID No. EPA–HQ–OAR–2021–0317–0814.

[39] See Document ID Nos. EPA–HQ–OAR–2021–0317–0568, EPA–HQ–OAR–2021–0317–0769, EPA–HQ–OAR–2021–0317–0844, and EPA–HQ–OAR–2021–0317–1267.

[40] See Document ID No. EPA–HQ–OAR–2021–0317–0727.

wellhead only well sites because, even though less equipment (and so fewer components) is present at a wellhead only well site, the wellhead itself is a source of emissions, which should be inspected for fugitive emissions.[41] Other commenters provided similar comments and urged the EPA to remove the exemption for wellhead only well sites because these well sites have other smaller equipment that leaks and malfunctions,[42] with large emissions having been observed from these sites,[43] even though these sites do not have major production and processing equipment. Further, commenters noted that well sites with equipment with potentially significant emissions should not be considered a wellhead only well site or excluded from regular monitoring. The commenter urged the EPA that, if the wellhead only well site exemption is retained, it must only apply to single wellhead sites. Even if no associated equipment is located at a wellhead only well site, sites with multiple wellheads can have a number of components and subsequently potential sources of fugitive emissions.[44] This same commenter, who opposes the 3 tpy threshold, noted that ''failure prone equipment'' such as storage vessels, separators, flares, and natural gas-driven pneumatic controllers often operate incorrectly and can cause significant emissions.[45] This commenter argued that sites with this type of equipment should be required to monitor on a frequent basis.

Another commenter noted that the one-time survey for sites less than 3 tpy does not address the problem of future leaks or malfunctions.[46] The commenter indicated that malfunctions account for a large amount of methane emissions and the commenter, therefore, recommended at least annual monitoring. Comments urging the EPA to exempt small, low producing wells were also received.[47] Specifically, one commenter argued that low producing wells are not disproportionately large emitters.[48] This commenter asked that the EPA exempt these wells, asserting that these sources can least afford monitoring and have relatively small emissions. The commenter further asked that the rule exempt wells defined by states as stripper wells.

As illustrated by the comments, which specifically highlight many potential challenges related to implementation, compliance assurance, and efficacy in reducing emissions, the EPA agrees that the fugitive emissions monitoring program that was proposed in the November 2021 proposal should be clarified and improved in order to address the issues identified by the various commenters. As explained below, after considering the comments, additional data, and a revised analysis, the EPA is proposing revised fugitive emissions applicability criteria, monitoring frequencies, and detection methods at well sites and centralized production facilities.

Fugitive emissions monitoring and repair modeling. In the November 2021 proposal, the EPA also solicited comment on other thresholds that could be used to set monitoring requirements for well sites, in lieu of using self-reported baseline emissions as a threshold. One of these options included an equipment-based approach, in which well sites with specific leak-prone equipment would have one set of requirements, while well sites with other equipment (or that lack leak-prone equipment) would have a different set of requirements. In comparison to a self-reported baseline emissions threshold, such an approach would ensure routine OGI monitoring takes place at sites that have equipment that is most likely to have fugitive emissions more frequently, while also being more straightforward for owners and operators to implement and for the EPA and state regulators to verify and enforce. The EPA received feedback and additional information in response to this solicitation and used that information to develop a new analysis based on this equipment-based concept.

To evaluate an equipment-based program, the EPA developed three distinct model plants. These model plants were designed to account for various equipment types located at sites and ranged from single wellhead only well sites to complex sites with various known sources of large emissions present. Specifically, these model plants include: (1) Single wellhead only well sites,[49] (2) wellhead only well sites with two or more wellheads, and (3) well sites or centralized production facilities[50] with major production and processing equipment. For the reasons explained later in this section, the EPA finds that small well sites have component counts, and thus emissions distributions, that are more comparable to single wellhead only well sites and less than multi-wellhead only well sites. The EPA has not modeled this small well site subcategory. Fugitive emissions from small well sites would originate from the same types of components (*e.g.,* valves, connectors, open-ended lines, or pressure relief devices) modeled with emissions for single wellhead only well sites, and the available data suggests that the single piece of equipment at the site would be of smaller size, and thus have fewer individual components, than those summarized for well sites and centralized production facilities with major production and processing equipment. However, for purposes of summarizing the component counts, the EPA is including small well sites in Table 7 along with the details of the number and type of equipment included in each of the model plants used for emissions modeling. The EPA finds that evaluating several types of model plants based on equipment and component counts is consistent with the empirical literature on fugitive emissions, including the conclusion from the U.S. Department of Energy's (DOE) recent marginal well study that a strong correlation was observed between the major equipment count and the frequency of fugitive emissions.[51] [52] The

[41] See Document ID No. EPA–HQ–OAR–2021–0317–0769.

[42] See Document ID No. EPA–HQ–OAR–2021–0317–0586.

[43] See Document ID No. EPA–HQ–OAR–2021–0317–0844.

[44] Id.

[45] Id.

[46] See Document ID No. EPA–HQ–OAR–2021–0317–1267.

[47] See Document ID Nos. EPA–HQ–OAR–2021–0317–0425 and EPA–HQ–OAR–2021–0317–0814.

[48] See Document ID No. EPA–HQ–OAR–2021–0317–0425.

[49] The EPA defines a wellhead only well site as a well site that contains one or more wellheads and no major production and processing equipment. Major production and processing equipment includes reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water. The EPA does not consider meters and yard piping as major production and processing equipment for purposes of determining if a well site is a wellhead only well site.

[50] Centralized production facilities include one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations.

[51] Bowers, Richard L. *Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells.* United States. *https://doi.org/10.2172/1865859.*

[52] The U.S. DOE marginal well study did not collect information on individual component counts on major equipment but did find a strong correlation to emissions based on the size of the site (defined by the major equipment count). Thus, the proposed definition of a small well site is limited

Continued

EPA is soliciting comment on the proposed model plants described in Table 7. The EPA is also seeking information on how to refine its approach to modeling fugitive emissions in the model plants developed for this analysis.

TABLE 7—WELL SITE MODEL PLANT COMPONENT COUNTS

Major equipment at well site	Count	Number of components at well site			
		Valves	Connectors	Open ended lines	Pressure relief valves
Single Wellhead Only Well Sites					
Gas Wellheads	1	10	38	1	0
Meter/Piping	1	13	48	1	1
Total # of Components:	112				
Small Well Sites					
Gas Wellheads	1	10	38	1	0
Meter/Piping	1	13	48	1	1
Other Equipment [a]	1	9	34	1	1
Total # of Components:	157				
Wellhead Only Well Sites with Two or More Wellheads					
Gas Wellheads	2	19	75	2	0
Meter/Piping	2	26	96	1	1
Total # of Components:	220				
Well Sites and Centralized Production Facilities with Major Production and Processing Equipment					
Gas Wellheads	2	19	75	2	0
Meter/Piping	2	26	96	1	1
Separators	2	44	137	8	3
In-Line Heaters	1	14	65	2	1
Dehydrators	1	24	90	2	2
Storage Vessel Thief Hatch	1	0	0	0	0
Total # of Components:	612				

[a] Major production and processing equipment that could be at a small well site includes compressors, glycol dehydrators, heater/treaters, separators, and uncontrolled storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water. Small well sites cannot include one or more controlled storage vessels, control device, natural gas-driven pneumatic controllers, or natural gas-driven pneumatic pumps. The component counts provided in this table are based on the average number of valves identified in industry provided data for a small well site (34 valves) and assuming 3.8 connectors per valve, 1 open-ended line, and 1 pressure relief device consistent with component counts provided for other equipment.[53]

In previous rulemakings, the EPA used component-level emissions factors that commenters on previous actions have stated are dated and not reflective of emissions detected through various recent measurement studies to determine baseline emissions and emissions reductions at various OGI monitoring frequencies.[54] In contrast, several comments on the November 2021 proposal identified various modeling simulation tools that can be utilized for this same purpose and that build in emissions data from various emissions measurement campaigns providing empirical emissions data.

One such modeling simulation tool is the Fugitive Emissions Abatement Simulation Toolkit (FEAST). FEAST is an open-source modeling framework developed to evaluate the effectiveness of fugitive emissions programs at oil and gas facilities by simulating various scenarios of leaks (and subsequent repairs) occurring over time using an empirical leak dataset according to a randomized process. FEAST supports a variety of detection technologies, including OGI, aerial surveys, drone surveys, and continuous monitoring systems and can model hybrid programs (*e.g.,* aerial surveys followed by ground-level OGI surveys). The effects of fugitive emissions monitoring and repair are simulated based on probability of detection (PoD) curves (or surfaces) for each monitoring method, which indicate the probability that a leak of a given size will be detected within a given survey (or time period for continuous monitoring technologies), and survey times (frequencies) are accounted for as finite time periods. The emissions present at the site during the modeled period of time are quantified, accounting for leak generation, identification, and repair, and emissions reductions can be calculated by comparing the simulated fugitive emissions program against a baseline scenario where no program is implemented.

The EPA recognizes there are several options to identify fugitive emissions,

to inclusion of a single piece of specific major production and processing equipment.

[53] See Document ID No. EPA–HQ–OAR–2017–0483–1006.

[54] See *EPA Responses to Public Comments on Reconsideration of New Source Performance Standards (NSPS) Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration 40 CFR part 60, subpart OOOOa,* located at Document ID No. EPA–HQ–OAR–2017–0483–2291.

ranging from simple sensory methods to advanced detection technologies. The EPA solicited comment on the inclusion of simple AVO checks that could be performed in conjunction with periodic OGI monitoring surveys to identify large emissions between OGI monitoring surveys in the November 2021 proposal. The EPA maintains that it is imperative to ensure that well sites and centralized production facilities are operated in a manner such that emissions are minimized. Further, OGI or other detection technologies are not necessary for identifying fugitive emissions from certain fugitive emissions components, such as open thief hatches. Therefore, the EPA examined the use of regular AVO inspections to provide for potential additional emissions reductions associated with fugitive emissions components, and to compel operators to address issues whenever they find indications of a potential leak during regular visits to sites.

One factor that can lead to fugitive emissions is a lack of maintenance, and it has been shown that when sites are not regularly visited, fugitive emissions can occur for long periods of time without any mitigation. For example, in comments provided on the October 15, 2018 proposed reconsideration for NSPS OOOOa, it was reported that some sites can be operating in a state of disrepair, including rusty well shafts, broken valves, or fallen trees on equipment.[55] While OGI and other monitoring technologies can be useful in identifying emissions from individual components, such as valves and connectors, these technologies require expensive equipment and specialized training of operators for identifying indications of fugitive emissions resulting from broken equipment or open thief hatches. On the other hand, AVO inspections are a useful tool for identifying when there are indications of a potential leak without the need for expensive equipment or specialized training of operators. For example, at sites that lack extensive background noise, a person would be able to hear if a high-pressure leak is present, which could present as a hissing sound. Field gas produced at well sites contains a mixture of methane and various VOCs, which have the potential to be detected by smell. Where the field gas contains a lot of condensate or other produced liquids, any resulting leaks would present as indications of liquids dripping or potentially puddles forming on the ground. In cold climates, ice formation on components could also indicate a potential leak. Finally, an open thief hatch on a storage vessel is easily identified with visual inspection.

The EPA is proposing a revised approach to address fugitive emissions at well sites and centralized production facilities that establishes the monitoring frequency and detection method (AVO and/or OGI) based on results obtained from using FEAST[56] to model various programs at the three model plants presented in this preamble. First, the EPA determined baseline methane emissions from each of the model plants using two leak generation rates, 0.5 and 1.0 percent. These leak generation rates represent the percentage of components leaking at any particular time at the site. The EPA chose these leak generation rates as a starting point for modeling to compare against measured emissions documented in credible empirical studies, such as the August 2021 paper by Rutherford, *et al.*[57] This proposed approach is responsive to feedback from commenters indicating that the emissions factors we relied upon in the November 2021 proposal undercount fugitive emissions, and recommending that we utilize models based on recent measured data that is more representative of fugitive emissions in the field. The results of the FEAST simulations for AVO and OGI monitoring are presented in the remainder of this section for each of the model plants. For ground based OGI, the EPA used a minimum detection limit of 60 g/hr consistent with the proposed camera specifications in 40 CFR 60.5397b(c)(7)(i)(B)[58] and assumed all leaks identified by OGI would be repaired within 30 days, consistent with the average repair time that would be required for fugitive emissions components.[59] The results of these models provide an estimate of the number of leaks identified during an inspection and the potential emissions reductions, which the EPA then applied to its cost-effectiveness analysis to determine the BSER for each well site model plant. The EPA is seeking information on its estimates of repair costs associated with identified leaks.

For purposes of evaluating the costs of the AVO inspections and OGI monitoring surveys, the EPA incorporated specific revisions into the cost analysis presented in the November 2021 proposal.[60] The capital and annual costs associated with each type of inspection or monitoring program are presented in Tables 8 and 9.

TABLE 8—WELL SITE MODEL PLANT COSTS ASSOCIATED WITH OGI MONITORING

Description of item	Costs ($)
Capital Costs for OGI Inspections	
Read rule and instructions (per 22 well sites)	$260.
Develop monitoring plan (per 22 well sites)	$2,600.
Setup recordkeeping system (per well site)	$900.
Costs for OGI Inspections (per well site)	
OGI surveys	$142/hr.
Repairs	$146 to $330/yr.
Resurvey	$3 to $20/yr.
Annual licensing fees of recordkeeping system	$870/yr.
Annual administrative costs for recordkeeping/data management	$325/yr.

[55] See Document ID No. EPA–HQ–OAR–2017–0483–2240.

[56] The EPA used FEAST version 3.1 to model the various programs. While the EPA used FEAST in this modeling exercise, the EPA would expect other available modeling simulation tools to produce similar results.

[57] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. *et al.* Closing the methane gap in US oil and natural gas production emissions inventories. *Nat Commun* 12, 4715 (2021). *https://doi.org/10.1038/s41467-021-25017-4.*

[58] The EPA is adopting the same OGI camera specifications for fugitive emissions components as those in NSPS OOOOa.

[59] The EPA is proposing to require a first attempt at repair within 30 days of identifying fugitive emissions, with final repair required within 30 days of the first attempt.

[60] See November 2021 TSD for additional information on costs of OGI monitoring at Document ID No. EPA–HQ–OAR–2021–0317–0166.

TABLE 8—WELL SITE MODEL PLANT COSTS ASSOCIATED WITH OGI MONITORING—Continued

Description of item	Costs ($)
Prepare and submit information in annual report	$195/yr.

TABLE 9—WELL SITE MODEL PLANT COSTS ASSOCIATED WITH AVO INSPECTIONS (ASSUMES NO OGI MONITORING)

Description of item	Costs ($)
Capital Costs for AVO Inspections	
Read rule and instructions (per 22 well sites)	$260.
Develop monitoring plan (per 22 well sites)	$260.
Setup recordkeeping system (per well site)	$65.
Costs for AVO Inspections (per well site)	
AVO inspection, including preparation and documentation	$65/hr.
Repairs	$89/yr to $178/yr.
Resurvey	$5/yr to $11/yr.
Prepare and submit information in annual report	$65/yr.

For OGI monitoring at well sites, the capital costs presented in Table 8 remain unchanged from the November 2021 proposal. The capital costs associated with the fugitive emissions program are expected to be the same for each model plant because these capital costs include the cost of developing a fugitive emission monitoring plan and purchasing or developing a recordkeeping data management system specific to fugitive emissions monitoring and repair. More discussion about the capital costs, which remain unchanged in this proposal, can be found in section XII.A.1.a of the November 2021 proposal (86 FR 63189; November 15, 2021).

When evaluating the annual costs of the fugitive emissions monitoring and repair requirements (*i.e.,* monitoring, repair, repair verification, data management licensing fees, recordkeeping, and reporting), the EPA considers costs at the individual site level. Estimates for these costs for OGI monitoring were mostly retained and consistent with the November 2021 proposal. However, the EPA incorporated the results of FEAST modeling for the newly developed model plants to include the modeled number of components identified as leaking, thus requiring repairs.[61] Even though the leak generation rate used in the FEAST model was set to 0.5 and 1.0 percent for purposes of emissions reduction analyses, the empirical dataset used includes all leaks measured across numerous studies, many of which are below the expected mass detection limit of OGI cameras. As such, only a portion of the leaks generated are identified and repaired via the OGI monitoring program (approximately 57 percent in this analysis). Specifically, the estimated annual number of components requiring repair resulting from an OGI survey, as modeled by FEAST, were 0.62 for single wellhead only and small well sites, 1.25 for multi-wellhead only well sites, and 3.7 for well sites and centralized production facilities with major production and processing equipment. The EPA utilized the same repair costs and resurvey costs as in the November 2021 proposal for OGI monitoring. All other inputs to the annual costs remain unchanged from the November 2021 proposal as well.

The estimated annual costs of the OGI-based fugitive emissions program at well sites and centralized production facilities range from $2,100 for annual monitoring to $6,000 for monthly monitoring for single wellhead only well sites. For multi-wellhead only well sites, the estimated annual costs of the fugitive emissions program range from $2,000 for annual monitoring to $5,900 for monthly monitoring. For well sites with major production and processing equipment, including those with controlled tanks, the estimated annual costs of the fugitive emissions program are estimated to range from $2,300 for annual monitoring to $7,000 for monthly monitoring. More detailed information on the capital and annual costs estimated for the fugitive emissions program can be found in the November 2021 TSD[62] and in the Supplemental TSD for this action located at Docket ID No. EPA–HQ–OAR–2021–0317.

For this supplemental proposal, the EPA separately evaluated the costs associated with AVO monitoring. The EPA assumed capital and annual costs for each individual well site and evaluated the costs in two ways: (1) Assuming an operator visits the site at least as frequently as the inspection (no additional travel costs), and (2) assuming additional travel costs because the site is not visited at the same frequency as the inspection. When accounting for the second scenario, the EPA assumed a travel time of 1.25 hours round trip and applied the same hourly rate for operators as is used for the development of a monitoring plan and other actions. Further, the EPA assumes an inspection time ranging from 15 minutes (single wellhead only well sites) to 1 hour (centralized production facilities) to account for the added complexity at larger sites. The EPA also assumed 1 repair per year for the single wellhead only, multi-wellhead only, and small well sites, and 2 repairs per year for larger well sites and centralized production facilities. While there is a lack of information on the emissions reductions achieved through an AVO inspection, the EPA is confident that specific indications of potential leaks (*e.g.,* open valves or thief hatches) would be obvious to any operator performing these inspections and discusses these in more detail below for each model plant.

The estimated annual costs of the AVO inspections at single wellhead only well sites and small well sites that are visited at least as frequently as the

[61] Assumes an average of 0.62, 1.25, and 3.7 leaks found annually, for model plants 1–3, respectively.

[62] See Document ID No. EPA–HQ–OAR–2021–0317–0166.

AVO inspection frequency range from $214 for annual inspections to $660 for monthly inspections. These estimates range from $300 for annual inspections to $1,630 for monthly inspections if additional travel costs are incorporated for these sites. For multi-wellhead only well sites, the estimated annual costs range from $265 for annual inspections to $1,150 for monthly inspections, and these costs range from $350 for annual inspections to $2,120 for monthly inspections when additional travel costs are added. For well sites with major production and processing equipment, the estimated annual costs range from $480 for annual inspections to $2,650 for monthly inspections, and this range increases to $560 for annual inspections to $3,620 for monthly inspections when additional travel costs are incorporated. More detailed information on the capital and annual costs estimated for the AVO inspections can be found in the Supplemental TSD for this action located at Docket ID No. EPA–HQ–OAR–2021–0317. The EPA is soliciting comment on all aspects of the estimated costs of the AVO inspection program, including labor rates and the costs of repair.

Single wellhead only well sites. The EPA has not previously defined single wellhead only well sites as fugitive emissions components affected facilities. For a single wellhead only well site, the most likely cause of emissions would be from an open valve allowing venting from the wellhead. In the U.S. DOE marginal well study, two of the top 10 largest leaks found were located at the wellhead and were the result of an open valve on the well surface casing, which allowed venting to the atmosphere. These two sources resulted in emissions of 6.9 kg/hr methane (66 tpy) and 7.8 kg/hr methane (76 tpy).[63] A third leak, also located at the wellhead, was identified as a hole in the side of the surface casing, resulting in emissions of 2.9 kg/hr methane (28 tpy) from this source. The other top 10 leak sources identified in the U.S. DOE marginal well study were on equipment that is not present at a single wellhead only well site (*e.g.,* separators or storage vessels). The types of emissions sources located at the wellhead, including these large emissions sources found in the U.S. DOE marginal well study, can be easily identified using AVO inspections and would not require the use of OGI for identification. Therefore, the EPA evaluated a periodic AVO inspection and repair program for addressing fugitive emissions from single wellhead only well sites.

First, the EPA modeled an AVO program at two leak generation rates (1.0 percent and 0.5 percent) to compare the resulting baseline methane emissions against empirical emissions data and identify which model results more closely reflect real-world emissions measurement campaign results. A comparison of the baseline methane emissions estimated at both of these leak generation rates to empirical data suggest that the 0.5 percent leak generation rate is more likely to be indicative of the actual average emissions from single wellhead only well sites. Various studies indicate that, while these sites can occasionally experience large emissions events, such events are not as frequent as at more complex sites, and thus do not warrant application of a higher average emissions baseline for purposes of determining the BSER for these sites.[64] The U.S. DOE marginal well study[65] measured methane average population emissions ranging from 0.26 to 0.56 tpy from wellheads examined during the study, with negligible emissions reported from meters. Similarly, the 2021 Rutherford *et al.* study estimated an average emissions factor for a single wellhead of 3.4 kg/day (0.95 tpy) and a single meter of 2.7 kg/day (0.75 tpy) for a total of 1.70 tpy from a single wellhead only well site.[66] Using the average emissions between these 2 studies, the baseline methane emissions are 1.13 tpy, which is consistent with the 0.5 percent leak generation rate results for our single wellhead only well sites, for which the FEAST model estimated a methane emissions baseline of 1.27 tpy (see Table 8). By contrast, the 1.0 percent leak generation rate baseline (2.97 tpy) is more than five times higher than the high end of the U.S. DOE marginal well study and 50 percent higher than the estimates from the Rutherford, *et al.* study. Therefore, the EPA is evaluating the cost of control for AVO inspections based on the modeled results for a 0.5 percent leak generation rate at single wellhead only well sites. Additional details of the model results, including those for the 1.0 percent leak generation rate, are included in the Supplemental TSD for this action located at Docket ID No. EPA–HQ–OAR–2021–0317.

TABLE 10—SUMMARY OF EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: AVO INSPECTIONS AT SINGLE WELLHEAD ONLY WELL SITES

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane ($/ton)	VOC ($/ton)	Methane ($/ton)	VOC ($/ton)
Single Wellhead Well Sites: Includes additional travel costs Single Pollutant Approach							
Annual	$296	0.11	0.03	$2,579	$9,278		
Semiannual	417	0.40	0.11	1,048	3,769	$429	$1,543
Quarterly	660	0.56	0.16	1,181	4,249	1,511	5,436
Bimonthly	904	0.63	0.17	1,443	5,190	3,618	13,017
Monthly	1,633	0.69	0.19	2,367	8,515	11,455	41,208
Single Wellhead Well Sites: Includes additional travel costs Multipollutant Approach							
Annual	296	0.11	0.03	1,289	4,639		

[63] Bowers, Richard L. *Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells.* United States. *https://doi.org/10.2172/1865859.* See Table 2 of the study for details on the top 10 emissions sources identified.

[64] See *https://pubs.acs.org/doi/10.1021/acs.est.0c02927*, *https://data.permianmap.org/pages/flaring*, and *https://www.edf.org/sites/default/files/documents/PermianMapMethodology_1.pdf.*

[65] Bowers, Richard L. *Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells.* United States. *https://doi.org/10.2172/1865859*. Marginal wells are defined in this study as producing less than 15 barrels of oil equivalent per day (boe/day) of combined oil and natural gas.

[66] Rutherford, J.S., Sherwin, E.D., Ravikumar, A.P. *et al.* Closing the methane gap in US oil and natural gas production emissions inventories. *Nat Commun* 12, 4715 (2021). *https://doi.org/10.1038/s41467-021-25017-4.*

TABLE 10—SUMMARY OF EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: AVO INSPECTIONS AT SINGLE WELLHEAD ONLY WELL SITES—Continued

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane ($/ton)	VOC ($/ton)	Methane ($/ton)	VOC ($/ton)
Semiannual	417	0.40	0.11	524	1,885	214	771
Quarterly	660	0.56	0.16	591	2,124	756	2,718
Bimonthly	904	0.63	0.17	721	2,595	1,809	6,509
Monthly	1,633	0.69	0.19	1,183	4,257	5,727	20,604

It is the EPA's understanding that single wellhead only well sites are not regularly visited. Instead, these sites are expected to only be visited when specific operations are necessary that require the presence of an operator on the site (*e.g.,* well workovers). Thus, the EPA finds it more appropriate to base decisions related to whether an AVO inspection frequency is reasonable on the analysis that includes additional travel costs to the site. Based on the information summarized in Table 10, which include additional travel costs, under the single pollutant approach where all costs are assigned to methane and zero cost to VOC, the semiannual, quarterly, and bimonthly (*i.e.,* every other month) frequencies are reasonable for methane emissions; similarly, where all costs are assigned to VOC and zero cost to methane, the semiannual, quarterly, and bimonthly frequencies are reasonable for VOC emissions. Under the multipollutant approach where the costs are divided equally between the two pollutants, all of the frequencies appear reasonable, including monthly monitoring.

The EPA next evaluated the incremental cost associated with advancing to each more frequent monitoring schedule to determine which frequencies would be reasonable for AVO inspections. As shown in Table 10 where additional travel costs are included, the incremental cost of going from semiannual to quarterly inspections is reasonable under both the single pollutant approach (for both methane and VOC individually) and the multipollutant approach. Under the single pollutant approach, the incremental cost of going from quarterly to bimonthly is not reasonable for either methane or VOC emissions. Under the multipollutant approach, the incremental cost of going from quarterly to bimonthly is not reasonable for VOC ($6,500/ton VOC), which means it is not cost-effective under the multipollutant approach. Therefore, the EPA finds it is not reasonable to require bimonthly AVO inspections.

In summary, the EPA finds that the BSER for single wellhead only well sites is quarterly AVO inspections for indications of potential leaks, with specific attention given to ensuring surface casing valves are closed to prevent the venting of emissions. The EPA is soliciting comment and additional data related to the costs and other potential causes of emissions on a single wellhead that could easily be identified using AVO inspections.

Small well sites. As stated in the November 2021 proposal, the EPA remains mindful about how the fugitive emissions monitoring requirements will affect small businesses. The EPA solicited comment in the November 2021 proposal on regulatory alternatives and additional information that would warrant considering a subset of sites differently based on a potentially different emissions profile, production levels, equipment onsite, or other factors. (86 FR 63173; November 15, 2021). The EPA examined data provided through an information collection request (ICR) distributed in 2016, data provided on equipment/component counts in relation to the October 15, 2018, proposed reconsideration of NSPS OOOOa from independent producers (many of whom are small businesses), data provided through comments on the November 2021 proposal from independent producers, and data contained in the U.S. DOE marginal well study to determine if a subset of well sites with major production and processing equipment should be considered differently.

Consistent with comments received on previous rulemakings, the EPA received comments on the November 2021 proposal requesting consideration of production volumes as a factor when establishing the BSER for well sites.[67] One commenter stated that the EPA has emphasized component counts instead of considering the significantly more important role that production rates and operating pressure play on the amount of fugitive emissions.[68] This commenter then referenced the U.S. DOE marginal well study as showing that most low production well sites (many of which are owned or operated by small businesses) emit less than 3 tpy of methane. However, that marginal well study concludes that the frequency and magnitude of emissions from well sites are more strongly correlated with equipment counts, not production rates.[69] Further, this study broke down emissions by site size and production levels and found that the smallest emissions rates were from the second production level bin (2 barrels of oil equivalent per day (boe/day) to 6 boe/day) and not the sites with production less than 2 boe/day. Another study issued in April 2022 by Omara, *et al.* concludes that approximately half of the methane emissions emitted from well sites in the U.S. comes from low production well sites (15 boe/day or less production rates).[70 71] However, the EPA notes that this study is not limited to

[67] See Document ID Nos. EPA–HQ–OAR–2021–0317–0425 and EPA–HQ–OAR–2021–0317–0814.

[68] See Document ID No. EPA–HQ–OAR–2021–0317–0814.

[69] Section 5.2.1 of the study concludes, ''The correlation between major equipment counts and site emission frequency (expressed as the number of detected emissions per piece of major equipment, *i.e.,* not absolute count of emissions), was strong with the categorical site 'size' variable and moderate (positive) with the numeric equipment count. Among evaluated numeric variables, site equipment counts also exhibited the strongest associations with both frequency and magnitude of sitewide emissions, exhibiting only a moderate positive correlation with detection frequency and weak associations with whole gas and methane emission rates. Weak correlations were also consistently detected among both the frequency and magnitude of emissions, total oil and gas production, and gas production rates.'' See Bowers, Richard L. *Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells.* United States. *https://doi.org/10.2172/1865859.* page 19.

[70] Omara, M., Zavala-Araiza, D., Lyon, D.R. *et al.* Methane emissions from US low production oil and natural gas well sites. *Nat Commun* 13, 2085 (2022). *https://doi.org/10.1038/s41467-022-29709-3.*

[71] The EPA notes that Omara *et al.* analyzed data from offsite measurements of methane emissions from well sites. These measurements would include methane from any leak, venting, flaring, or other source onsite and, therefore, conclusions from this study cannot be directly applied to the specific fugitive sources covered by this action.

fugitive emissions, and the overall impacts on emissions reductions achieved if these rules are finalized as proposed, would target the emissions reported in that study as a whole. Therefore, the EPA does not have compelling information that suggests production levels should provide the basis for consideration of different fugitive emissions requirements for well sites.

While the EPA does not find that production rates correlate to the amount of fugitive emissions and therefore should not be used as a basis for establishing different fugitive emissions monitoring requirements among well sites, we do find that the empirical data described supports distinguishing among well sites based on equipment and component counts. As explained earlier in this section, the EPA utilized model plants, with different equipment and component counts to differentiate fugitive emissions monitoring programs using AVO and OGI through FEAST modeling simulations.

Based on comments received on the October 15, 2018, reconsideration proposal, the EPA has evaluated if certain well sites with major production and processing equipment are more comparable in total component counts to either of the wellhead only model plants. For example, one commenter in 2018 provided average equipment and/or component counts for sites in various states that are owned and operated by independent producers, many of whom are small businesses. These counts included the number of storage vessels, wellheads, and valves, specifically.[72] That information suggests that there are well sites owned and operated by small businesses that are predominantly composed of single wellheads, with 1 to 2 storage vessels and 11 to 53 valves. These component counts are significantly lower than those estimated for the model plants developed for this supplemental proposal that include major production and processing equipment, which include 127 total valves. This suggests that certain well sites are smaller than our model facilities, and that as a result the model may overstate emissions reductions, and thus cost-effectiveness, for fugitive emissions programs at such small sites. In fact, the EPA anticipates that there are well sites with major production and processing equipment that are of similar component counts as the single wellhead only well site (total components equal to 112, with 23 total valves). Therefore, the EPA does find that a separate BSER determination is warranted for certain small sites.

The EPA is proposing to define a small well site, for purposes of the fugitive emissions monitoring requirements, as a well site that contains a single wellhead, no more than one piece of certain major production and processing equipment, and associated meters and yard piping. The major production and processing equipment could include a single separator, glycol dehydrator, heater/treater, compressor,[73] or uncontrolled storage vessel. It cannot include controlled storage vessels, control devices, or natural gas-driven pneumatic controllers, as those are known to be sources of large emissions events. Further, the equipment allowed at these small sites would not include any affected/designated facilities, nor would it include a CVS which is subject to quarterly OGI monitoring as explained in section IV.K. The EPA is proposing this narrow definition to ensure that sites with leak-prone equipment that requires OGI (or other advanced technology) monitoring are not present at the site. Based on the EPA's analysis of data collected from an ICR distributed in 2016 and applied to the universe of wells operating in 2019, it is estimated that approximately 95,000 well sites would meet this definition (nationwide), or approximately 12 percent of the total nationwide well site count.

Surface casing valves and thief hatches on an uncontrolled storage vessel are the most likely emissions sources for these small well sites. As discussed for single wellhead only well sites, the surface casing valve can easily be identified as open or closed during an AVO inspection and would not require the use of OGI to detect the leak. Similarly, the use of OGI is not necessary to be able to identify if a thief hatch is not closed. For example, the hatch may be fully open, left unlatched and ''chattering'' with fluctuations from the storage vessel pressures, or have visible indications of liquids such as staining around the hatch. Therefore, the EPA has evaluated AVO inspections to determine the BSER for small well sites.

The EPA utilized the same model results as those provided for single wellhead only well sites. For that model plant, the baseline methane emissions were estimated at 1.27 tpy. In the U.S. DOE marginal well study, the average methane emissions rate for a thief hatch was 0.20 tpy. Likewise, the emissions factor for tank leaks identified in Rutherford, *et al.* was 0.195 tpy (0.7 kg/day). Therefore, the EPA finds it appropriate to utilize the same model results as those presented in Table 10 for single wellhead only sites to determine the BSER for small well sites. Based on the information presented in Table 10, and our conclusions on the cost-effectiveness of the options for single wellhead only well sites, the EPA proposes quarterly AVO inspections for monitoring fugitive emissions at small well sites.

Additionally, for thief hatches and other openings on storage vessels that are proposed as fugitive emissions components, the EPA is proposing to require an equipment standard as part of the fugitive emissions work practice that requires these thief hatches to remain closed and sealed at all times except during sampling, adding process material, or attended maintenance operations.[74] This type of equipment standard has been used in other leak detection work practices where open-ended lines and valves are required to be equipped with a closure device (*e.g.,* cap or plug) to seal the open-end of the line or valve, thus preventing leaks from going to the atmosphere. An open thief hatch, even on an uncontrolled storage vessel, would still contribute fugitive emissions and maintaining the thief hatch in a closed position will provide for reduction of emissions at no additional cost. Further, one commenter provided a recommendation that the EPA should propose requirements to maintain thief hatches closed and sealed until the potential emissions from a tank battery exceeds the applicability threshold requiring controls for storage vessels and that AVO monitoring should be used to verify compliance with this standard.[75] The EPA agrees with this recommendation that AVO inspections would be appropriate to verify compliance with the proposed ''closed and sealed'' requirement, and therefore, is proposing this requirement for thief hatches that are fugitive emissions components.

Given all of the factors described in this section (fewer equipment, less emissions, many are owned and operated by small businesses, do not contain leak-prone equipment that needs OGI to identify emissions), the

[72] See Document ID No. EPA–HQ–OAR–2017–0483–1006.

[73] The EPA has proposed to exclude compressors located at well sites from being affected facilities because these are generally small compressors that do not have significant emissions. Compressors have been excluded from being affected facilities in NSPS OOOO and NSPS OOOOa as well.

[74] See section IV.J for solicitation for comment on mechanisms, such as alarms and automatically closing thief hatches that could also provide assurance that thief hatches meet this requirement.

[75] See Document ID No. EPA–HQ–OAR–2021–0317–0814.

EPA is proposing quarterly AVO surveys and the closed and sealed requirement for thief hatches as the BSER for reducing fugitive emissions at small well sites. The EPA is soliciting comment on this definition for small well sites, including whether additional metrics should be used beyond equipment counts, as well as the proposed standards and requirements for this subcategory of sites.

Multi-wellhead only well sites. For wellhead only well sites with two or more wellheads, the EPA anticipates that the same large emissions source (*i.e.,* surface casing valves) would be present. In addition to these valves on the wellheads, these sites have additional piping, and thus connection points and valves that also present a potential source of fugitive emissions. Emissions from these types of components are generally smaller, and not easily identifiable using AVO. Further, the estimated component count for the multi-wellhead only well sites is at least double that of the single wellhead only well site (and in many cases much larger), thus, the EPA has determined that additional analysis including OGI monitoring is appropriate. As with the AVO inspection analysis for single wellhead only well sites, the EPA evaluated both a 0.5 percent leak generation rate and a 1.0 percent leak generation rate for this model plant to determine which model results were representative of the fugitive emissions measurement data provided in the same studies used for comparison for single wellhead only well sites analysis.

For multi-wellhead only well sites, the baseline emissions were estimated at 2.66 tpy methane and 4.68 tpy methane at the 0.5 percent and 1.0 percent leak generation rates, respectively. Applying the wellhead emissions range from the U.S. DOE marginal well study to a site with two wellheads results in baseline methane emissions of 0.52 to 1.12 tpy.[76] Applying the wellhead emissions from the Rutherford, *et al.* study to a site with two wellheads and meters results in baseline methane emissions of 3.40 tpy. Using the average emissions between these 2 studies, the baseline methane emissions are 2.26 tpy, which is consistent with the 0.5 percent leak generation rate model plant results. Accordingly, the EPA is evaluating the OGI monitoring frequencies based on the modeled results for the 0.5 percent leak generation rate for purposes of this proposal. Additional details of the model results, including those for the 1.0 percent leak generation rate, are included in the Supplemental TSD for this action located at Docket ID No. EPA–HQ–OAR–2021–0317.

TABLE 11—SUMMARY OF EMISSION REDUCTIONS AND COST-EFFECTIVENESS: OGI MONITORING AT WELL SITES WITH TWO OR MORE WELLHEADS

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane ($/ton)	VOC ($/ton)	Methane ($/ton)	VOC ($/ton)
Well Sites with Two or More Wellheads: 0.5 Percent Leak Generation Rate Single Pollutant Approach							
Baseline	....	2.66	0.74	....	....	....	....
Annual	$1,972	1.18	0.33	$1,677	$6.034	....	....
Semiannual	2,327	1.79	0.50	1,300	4,675	$578	$2,078
Quarterly	3,037	2.06	0.57	1,473	5,300	2,620	9,425
Bimonthly	3,747	2.15	0.60	1,741	6,263	7,799	28,055
Monthly	5,877	2.24	0.62	2,619	9,420	23,140	83,246
Well Sites with Two or More Wellheads: 0.5 Percent Leak Generation Rate Multipollutant Approach							
Baseline	....	2.66	0.74	....	....	....	....
Annual	1,972	1.18	0.33	839	3,017	....	....
Semiannual	2,327	1.79	0.50	650	2,338	289	1,039
Quarterly	3,037	2.06	0.57	737	2,650	1,310	4,713
Bimonthly	3,747	2.15	0.60	870	3,131	3,899	14,028
Monthly	5,877	2.24	0.62	1,309	4,710	11,570	41,623

Based on the information summarized in Table 11, under the single pollutant approach where all costs are assigned to methane and zero cost to VOC, all frequencies except monthly appear reasonable for methane emissions; where all costs are assigned to VOC and zero cost to methane, only annual, semiannual, and quarterly monitoring frequencies appear reasonable for VOC emissions. Under the multipollutant approach where the costs are divided equally between the two pollutants, all frequencies appear reasonable when compared directly to a baseline of no OGI monitoring.

The EPA next evaluated the incremental cost associated with advancing to a more frequent monitoring schedule to determine if those additional costs are reasonable for achieving the additional emissions reductions. Under the single pollutant approach, the incremental cost of going from semiannual to quarterly monitoring for well sites with two or more wellheads is $2,600/ton methane and $9,400/ton of VOC. These incremental costs are not reasonable and are outside the range of costs the EPA has found reasonable for this source category. Under the multipollutant approach, the incremental costs of going from semiannual to quarterly monitoring is $1,310/ton methane and $4,713/ton VOC, which is within the range the EPA has found reasonable for this source category.

Next the EPA evaluated whether AVO inspections should also be utilized, in combination with the OGI surveys to allow for faster identification of those larger emissions sources (*i.e.,* surface casing valves) between OGI surveys. As

[76] The emissions for meters in the U.S. DOE marginal well study were negligible and do not impact the total average baseline emissions for this type of site.

explained above, fugitive emissions from these large emission sources can be detected through AVO inspections, which are less expensive than OGI. Therefore, the EPA evaluated a combination of semiannual OGI and various frequencies of AVO inspections to determine if this combined program would be as effective as, but less expensive than, quarterly OGI in light of the number and significance of fugitive emissions that can be identified via AVO at this type of well site. The EPA analyzed AVO inspections at quarterly, bimonthly, and monthly frequencies only because annual or semiannual AVO inspection frequencies would occur at the same time as at least one of the OGI surveys if the EPA were to require OGI monitoring for multi-wellhead only well sites. Further, the EPA determined that some costs associated with the AVO inspections would be less than those provided in Table 9 because those costs are also included in the OGI monitoring costs in Table 8. For example, there would be no additional costs to read the rule, travel for inspections that overlap with OGI monitoring surveys, or additional recordkeeping system costs. That is, in the evaluation of semiannual OGI with quarterly AVO inspections, only two AVO inspections would be required outside of the OGI surveys, thus the inspection costs would be half what is estimated for quarterly AVO inspections. Table 12 summarizes the results of this combined program for multi-wellhead only well sites.

TABLE 12—SUMMARY OF EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: COMBINED OGI MONITORING AND AVO INSPECTIONS AT MULTI-WELLHEAD ONLY WELL SITES

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane ($/ton)	VOC ($/ton)	Methane ($/ton)	VOC ($/ton)
Multi-Wellhead Well Sites: Includes additional travel costs Single Pollutant Approach							
Semiannual OGI	$2,327	1.79	0.50	$1,300	$4,653		
Semiannual OGI + Quarterly AVO	2,651	1.99	0.55	1,331	4,788	$1,606	$6,038
Semiannual OGI + Bimonthly AVO	2,973	2.09	0.58	1,425	5,125	3,394	12,210
Semiannual OGI + Monthly AVO	3,671	2.16	0.60	1,822	6,554	12,728	45,787
Multi-Wellhead Well Sites: Includes additional travel costs Multipollutant Approach							
Semiannual OGI	2,327	1.79	0.50	650	2,327		
Semiannual OGI + Quarterly AVO	2,651	1.99	0.55	665	2,394	803	3,019
Semiannual OGI + Bimonthly AVO	2,973	2.09	0.58	712	2,563	1,697	6,105
Semiannual OGI + Monthly AVO	3,671	2.16	0.60	911	3,277	6,364	22,893

Under the single pollutant approach, a combined program of semiannual OGI and quarterly or bimonthly AVO are reasonable for methane and VOC emissions individually. However, when incremental costs are considered, the costs of going from quarterly to bimonthly AVO inspections is not reasonable for either pollutant under the single pollutant approach. Under the multipollutant approach, all combinations appear reasonable when evaluated against a baseline of no monitoring. However, the multipollutant incremental costs are not reasonable for a combined program of semiannual OGI and bimonthly AVO because the multipollutant VOC costs exceed the range that the EPA considers reasonable for this source category at $6,105/ton VOC. Therefore, the EPA finds it is reasonable to consider either quarterly OGI monitoring or a combination of semiannual OGI and quarterly AVO as cost-effective measures to reduce fugitive emissions from multi-wellhead only well sites.

Finally, the EPA compared the emissions reductions and costs associated with the quarterly OGI (most stringent and cost-effective OGI frequency) to the combined program of semiannual OGI with quarterly AVO inspections. The emissions reductions for these two monitoring programs are comparable (2.06 tpy of methane and 0.57 tpy of VOC for quarterly OGI versus 1.99 tpy of methane and 0.55 tpy of VOC for semiannual OGI with quarterly AVO), but the costs are not. The annual cost of quarterly OGI monitoring is $3,037, whereas the annual cost of the combined OGI and AVO program is $2,489. For a combined semiannual OGI and quarterly AVO program the same number of surveys would be conducted at the site (with 2 surveys being OGI with AVO and 2 surveys being AVO only). The EPA is proposing the combined program of semiannual OGI with quarterly AVO as the BSER for multi-wellhead only well sites because of the comparable emissions reductions, same number of total surveys per year, and lower annual costs for the program overall. The EPA solicits comment on this proposed standard, including the basis for the decision to propose semiannual OGI with quarterly AVO inspections rather than quarterly OGI.

Well sites with major production and processing equipment and centralized production facilities. The EPA evaluated a third model plant, which contains major production and processing equipment. The EPA performed the same analyses to evaluate the BSER for fugitive emissions components at well sites and centralized production facilities with major production and processing equipment as performed for multi-wellhead only well sites. Table 13 summarizes the cost-effectiveness information for each OGI monitoring frequency, and Table 14 summarizes the costs of a combined program using both OGI and AVO.

As discussed for the single wellhead only and multi-wellhead only well site analyses, the EPA modeled OGI monitoring programs for both a 1.0 percent and 0.5 percent leak generation rate and compared the resulting modeled emissions to the same empirical study data to determine which model was more representative of the emissions at this type of well site. The baseline emissions resulting from FEAST for this model plant were 15.40 tpy methane and 8.51 tpy methane at 1.0 percent and 0.5 percent leak generation rate, respectively. The highest average site emissions were calculated at 3.3 tpy methane for large natural gas sites and 4.0 tpy methane for large oil sites in the U.S. DOE marginal well study, which the EPA anticipates is similar to the model plant with major production and processing equipment. The EPA next applied the emissions factors from the Rutherford, *et al.* study to the equipment counts in our model plant, resulting in emissions of 7.1 tpy methane. These emissions suggest the 0.5 percent leak generation rate is more appropriate for consideration of the costs of control and appropriate OGI monitoring frequency for well sites and centralized production facilities with major production and processing equipment.

TABLE 13—SUMMARY OF EMISSION REDUCTIONS AND COST-EFFECTIVENESS: OGI MONITORING AT WELL SITES WITH MAJOR PRODUCTION OR PROCESSING EQUIPMENT

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane ($/ton)	VOC ($/ton)	Methane ($/ton)	VOC ($/ton)
Well Sites and Centralized Production Facilities: 0.5 percent leak generation rate Single Pollutant Approach							
Baseline	....	8.51	2.37	....	....	....	....
Annual	$2,162	3.99	1.11	$542	$1,951	....	....
Semiannual	2,588	5.73	1.59	452	1,624	$244	$879
Quarterly	3,440	6.61	1.84	520	1,872	969	3,487
Bimonthly	4,292	6.97	1.94	616	2,217	2,398	8,625
Monthly	6,848	7.26	2.02	943	3,393	8,676	31,212
Well Sites and Centralized Production Facilities: 0.5 percent leak generation rate Multipollutant Approach							
Baseline	....	8.51	2.37	....	....	....	....
Annual	2,162	3.99	1.11	271	975	....	....
Semiannual	2,588	5.73	1.59	226	812	122	439
Quarterly	3,440	6.61	1.84	260	936	485	1,744
Bimonthly	4,292	6.97	1.94	308	1,108	1,199	4,313
Monthly	6,848	7.26	2.02	472	1,697	4,338	15,606

Based on the information summarized in Table 13 for the 0.5 percent leak generation rate, under the single pollutant approach where all costs are assigned to methane and zero cost to VOC, all frequencies appear reasonable for methane emissions; where all costs are assigned to VOC and zero cost to methane, all frequencies appear reasonable for VOC emissions. Similarly, under the multipollutant approach where the costs are divided equally between the two pollutants, all frequencies appear reasonable when compared directly to a baseline of no OGI monitoring.

The EPA next evaluated the incremental cost associated with advancing to each more frequent monitoring schedule. As shown in Table 13 for the single pollutant approach, the incremental costs of going from quarterly to bimonthly monitoring for these larger well sites are $2,398/ton methane and $8,625/ton of VOC. These incremental costs are outside the range of costs the EPA has found reasonable for this source category (*i.e.,* $2,165/ton methane and $5,540/ton VOC). Under the multipollutant approach, the incremental costs of going from quarterly to bimonthly monitoring are $1,199/ton methane and $4,313/ton VOC, which is within the range the EPA has found reasonable for this source category.

Next the EPA evaluated the costs of a combined program for well sites and centralized production facilities, using quarterly OGI as a baseline with AVO inspections added at bimonthly, and monthly frequencies to determine if this combined program would be as effective as, but less expensive than, bimonthly OGI. The EPA did not evaluate annual, semiannual, or quarterly AVO inspection frequencies because those would occur at the same time as at least one of the OGI surveys if the EPA were to require quarterly OGI monitoring for well sites and centralized production facilities with major production and processing equipment. However, the EPA is soliciting comment on the costs and effectiveness of a combined program of quarterly OGI surveys in combination with quarterly AVO inspections that are offset by one month, such that eight total fugitive surveys would take place over the course of a year. Further, the EPA determined that some costs associated with the AVO inspections would be less than those provided in Table 9 because those costs are also included in the OGI monitoring costs in Table 8. For example, there would be no additional costs to read the rule, travel for inspections that overlap with OGI monitoring surveys, or additional recordkeeping system costs. Table 14 summarizes the results of this combined program for well sites and centralized production facilities with major production and processing equipment.

TABLE 14—SUMMARY OF EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: COMBINED OGI MONITORING AND AVO INSPECTIONS AT WELL SITES AND CENTRALIZED PRODUCTION FACILITIES

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane ($/ton)	VOC ($/ton)	Methane ($/ton)	VOC ($/ton)
Well Sites and Centralized Production Facilities: Assumes no additional travel costs Single Pollutant Approach							
Quarterly OGI	$3,440	6.61	1.84	$520	$1,872	....	....

TABLE 14—SUMMARY OF EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: COMBINED OGI MONITORING AND AVO INSPECTIONS AT WELL SITES AND CENTRALIZED PRODUCTION FACILITIES—Continued

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	VOC emission reduction (tpy/site)	Cost-effectiveness		Incremental cost-effectiveness	
				Methane ($/ton)	VOC ($/ton)	Methane ($/ton)	VOC ($/ton)
OGI + Bimonthly AVO	4,232	6.93	1.93	611	2,198	2,497	8,981
OGI + Monthly AVO	5,021	7.10	1.97	707	2,545	4,616	16,608
Well Sites and Centralized Production Facilities: Assumes no additional travel costs Multipollutant Approach							
Quarterly OGI	3,440	6.61	1.84	260	936	....	....
OGI + Bimonthly AVO	4,232	6.93	1.93	305	1,099	1,248	4,491
OGI + Monthly AVO	5,021	7.10	1.97	354	1,272	2,308	8,304

Under the single pollutant approach, a combined program of quarterly OGI and bimonthly or monthly AVO are reasonable for methane and VOC emissions individually. When incremental costs are considered, the costs of going from bimonthly to monthly AVO inspections is not reasonable for either pollutant under the single pollutant approach. Under the multipollutant approach, all combinations appear reasonable when evaluated against a baseline of no monitoring. The multipollutant incremental costs are not reasonable for a combined program of quarterly OGI and monthly AVO. However, the EPA finds it is reasonable to consider either a bimonthly OGI monitoring program alone or a combination of quarterly OGI and bimonthly AVO as cost-effective measures to reduce fugitive emissions from well sites and centralized production facilities that include major production and processing equipment.

Finally, the EPA compared the emissions reductions achieved by the combined quarterly OGI and bimonthly AVO program to a bimonthly OGI program with no AVO inspections. While both programs appear cost-effective, the combined program achieves comparable emissions reductions to the bimonthly OGI program (6.93 tpy of methane and 1.93 tpy of VOC for the combined program, compared to 6.97 tpy of methane and 1.94 tpy of VOC for the bimonthly OGI program) at a comparable cost ($4,232 for the combined program compared to $4,292 for the bimonthly OGI program), and results in more total visits to the well site or centralized production facility. Specifically, a total of four OGI surveys and four AVO inspections would be completed, for a total of eight surveys at the site each year (two of the bimonthly AVO inspections would occur at the same time as two of the OGI surveys) whereas bimonthly OGI would result in six surveys of the site each year. Additional visits to the site create more opportunities to find and fix fugitive emissions, including the large emissions that can be detected by AVO inspections. Therefore, the EPA finds that the BSER for well sites and centralized production facilities with major production and processing equipment is quarterly OGI surveys combined with bimonthly AVO inspections and therefore is proposing this combined program as the standard for reducing fugitive emissions at these sites. The EPA solicits comment on this proposed standard, including the basis for the decision to propose quarterly OGI monitoring with bimonthly AVO inspections rather than bimonthly OGI monitoring.

Because the EPA finds that the combination of quarterly OGI monitoring and bimonthly AVO inspections are reasonable, the EPA is proposing this combination of monitoring frequencies and methods as the BSER for well sites and centralized production facilities with major production and processing equipment. The EPA is specifically proposing to require this combination program for fugitive emissions components affected facilities located at well sites or centralized production facilities that contain the following major production and processing equipment:

- One or more controlled storage vessels or tank batteries,
- One or more control devices,
- One or more natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps, or
- Two or more pieces of major production and processing equipment not otherwise specified.[77]

The EPA is proposing to define this subcategory as well sites with one or more controlled storage vessels, control devices, or natural gas-driven pneumatic controllers because those sources individually are known sources of super-emitter emissions events (see section IV.C) and are subject to quarterly OGI for compliance assurance (storage vessels and pneumatic controllers) or are subject to other continuous monitoring requirements (control devices). Further, the EPA is defining this subcategory as well sites with two or more other major production and processing equipment because the model plant includes two separators, which are another source that can contribute to large emissions when combined with a storage tank. As explained previously related to small well sites, the EPA is proposing an additional subcategory of well sites to recognize that this model plant may overstate the fugitive emissions from well sites that have only one piece of major production and processing equipment that is not a controlled storage vessel, control device, pneumatic controller, or pneumatic pump. Consistent with comments received on the November 2021 proposal, the EPA understands that the industry is aware that this specific equipment (controlled storage vessels, control devices, and natural gas-driven pneumatic controllers) is more prone to emissions and that fugitive surveys using OGI present an opportunity to identify these emissions. However, the EPA is not expanding the definition of fugitive emissions component to include controlled tank batteries, control devices, or natural gas-driven pneumatic controllers as explained earlier in this section because those sources are subject to separate requirements that are intended to ensure proper operation (including regular inspections, in the case of controlled tank batteries and natural gas-driven pneumatic controllers).

In summary, the EPA is proposing that the BSER for well sites with major

[77] Major production and processing equipment includes centrifugal and reciprocating compressors, separators, glycol dehydrators, heater/treaters, and storage vessels.

production and processing equipment and centralized production facilities, is a combination program consisting of bimonthly AVO inspections and quarterly OGI monitoring and the closed and sealed requirement for thief hatches (as explained in the discussion on small well sites).

Well closure plans. The EPA is proposing that owners and operators of each well site or centralized production facility may stop the required fugitive emissions monitoring and repair for that site when the well site has been properly closed because in that event there should not be any equipment or other fugitive components onsite for monitoring. This would also help address concerns cited by many stakeholders regarding continuing emissions from orphaned wells and unplugged idled wells. In the November 2021 proposal, the EPA solicited comment and information on idled and unplugged wells due to the EPA's understanding and concern that these non-producing oil and natural gas wells are generally unmanned and many are in disrepair. 86 FR 63240 (November 15, 2021). The EPA notes that ''some states and NGOs also have elevated concerns about the potential number of wells that could be abandoned in the near future as they reach the end of their productive lives.'' *Id.*

In addition, since promulgation of NSPS OOOOa, the EPA has received various questions from owners and operators related to when fugitive emissions monitoring applies if a well is shut-in, idled, or permanently closed. The Agency is therefore proposing specific requirements in NSPS OOOOb to ensure clarity for well sites and centralized production facilities subject to the rule. Studies have shown that idled wells can have fugitive emissions, and in some cases these emissions can be very large.[78] [79] The EPA finds that these data demonstrate the importance of continued fugitive emissions monitoring on a routine basis to ensure that fugitive emissions continue to be addressed throughout the life of the well site, even during periods when the wells at the site are shut-in or idled and could be put back into production at a later date.

However, there is a point at the end of a well site's useful life where the EPA does anticipate the cessation of fugitive emissions monitoring is appropriate, when all wells at the well site have been permanently plugged and all equipment has been removed. To demonstrate that a well site has reached that point where it is appropriate to cease fugitive monitoring, the EPA is proposing to require owners and operators to develop and submit a well closure plan within 30 days of the cessation of production from all wells at the well site or centralized production facility. The plan would include: (1) The steps necessary to close all wells at the well site, including plugging of all wells; (2) the financial requirements and disclosure of financial assurance to complete closure; and (3) the schedule for completing all activities in the closure plan. The EPA is also proposing to require that owners and operators submit a notification to the Agency 60 days before beginning well closure activities. The EPA solicits comment on additional provisions that could be added, including, for example, automatic consequences for missed monitoring reports, as a means of assuring that companies remain engaged with the site, including conducting monitoring, until all the wells at the site are properly closed.

Finally, the EPA is proposing that when the well closure activities have been completed, prior to ceasing regular monitoring, the owner or operator would be required to conduct a survey of the well site using OGI. The purpose of this survey is to ensure there are no emissions identified with OGI. If any emissions are identified, the owner or operator would be required to take steps to eliminate those emissions and resurvey. The EPA is proposing that once the OGI survey indicates no emissions are present, the well site would be considered closed and no further fugitive emissions monitoring would be required.

The EPA finds that the requirements described above not only would allow owners and operators of well sites and centralized production facilities to stop fugitive emissions monitoring at a clearly defined point where fugitive emissions are no longer a concern at the site, these proposed requirements would also prevent well sites from becoming orphaned or left in an idled and unplugged state with no form of emissions monitoring and repair. The EPA assesses the continued monitoring of well sites will help identify emissions and maintain the well site such that it does not fall into disrepair. The EPA is soliciting comment on these planning and monitoring requirements. Lastly, because a well site could have a long useful life, during which there may be different owners or operators, the EPA is proposing to require owners and operators to report, through the annual report, any changes in ownership at individual well sites so that it is clear who the responsible owners and operators are until the site is plugged and closed and fugitive emissions monitoring is no longer required. We propose this reporting requirement as an important step in maintaining transparency for the responsible owner or operator and will also prevent well sites from becoming orphaned in the future. The EPA solicits comment on this additional reporting requirement, including other mechanisms for obtaining this information.

iii. Summary of Proposed Standards

Definition of fugitive emissions component. Based on changes made and discussed under section IV.A.1.a.ii of this preamble, the EPA is proposing to define fugitive emissions component as any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and CVS not subject to 40 CFR 60.5411b, thief hatches or other openings on a storage vessel not subject to 40 CFR 60.5395b, compressors, instruments, meters, and yard piping.

Monitoring requirements. The EPA is proposing the following requirements for each subcategory of well sites not located on the Alaska North Slope.

- Single wellhead only well sites and small well sites: Quarterly AVO inspections.
- Multi-wellhead only well sites: Semiannual OGI (or EPA Method 21) monitoring and quarterly AVO inspections at wellhead only well sites with two or more wellheads.
- Well sites with major production and processing equipment and centralized production facilities: Quarterly OGI (or EPA Method 21) monitoring and bimonthly AVO inspections at well sites and centralized production facilities with: (1) One or more controlled storage vessels or tank batteries; (2) one or more control devices; (3) one or more natural gas-driven pneumatic controllers; or (4) two or more pieces of major production or processing equipment not listed in items (1) through (3).

Where semiannual monitoring is proposed, subsequent semiannual

[78] Amy Townsend-Small and Jacob Hoschouer. ''Direct measurements from shut-in and other abandoned wells in the Permian Basin of Texas indicate some wells are a major source of methane emissions and produced water.'' 2021 *Environ. Res. Lett.* 16 054081. *https://iopscience.iop.org/article/10.1088/1748-9326/abf06f.*

[79] Eric D. Lebel, Harmony S. Lu, Lisa Vielstädte, Mary Kang, Peter Banner, Marc L. Fischer, and Robert B. Jackson. ''Methane Emissions from Abandoned Oil and Gas Wells in California.'' *Environmental Science & Technology* 2020 *54* (22), 14617–14626. DOI: 10.1021/acs.est.0c05279.

monitoring would occur at least 4 months apart and no more than 7 months apart. Where quarterly monitoring is proposed, subsequent quarterly monitoring would occur at least 60 days apart and quarterly monitoring may be waived when temperatures are below 0 degrees Fahrenheit (°F) for two of three consecutive calendar months of a quarterly monitoring period.

When fugitive emissions are identified through AVO inspections, the EPA is proposing to require that repairs be completed within 15 days after the first attempt. The EPA is proposing a 15-day repair timeframe so that the monthly AVO inspections do not overlap the repair schedule. When fugitive emissions are identified through OGI surveys, the EPA is proposing to require a first attempt at repair within 30 days of detecting the fugitive emissions, with final repair, including resurvey to verify repair, completed within 30 days after the first attempt, consistent with the November 2021 proposal. Finally, we are proposing to require owners and operators to develop a fugitive emissions monitoring plan that covers all the applicable requirements for the fugitive emissions components located at a well site or centralized production facility. This monitoring plan would also include specific procedures, defined by the owner or operator, to ensure consistency in surveys conducted with either OGI or EPA Method 21, and to ensure that these surveys are conducted appropriately for identifying fugitive emissions from components at the site.

Monitoring (AVO and OGI) surveys would be required to continue until the owner or operator permanently closes the well site. Closure includes completing well closure activities specified by the owner or operator in a well closure plan. A final OGI survey of the well site would be required to ensure there are no emissions following plugging all of the wells at the site and completing closure activities. If emissions are identified during this OGI survey, the rule would require eliminating those emissions within the same timeline as required for regular OGI surveys (first attempt within 30 days of identification, with final repair within 30 days of the first attempt) and a resurvey of the whole site to verify emissions have been addressed.

Recordkeeping and Reporting Requirements. Specific recordkeeping and reporting requirements would also apply for each fugitive emissions affected facility. Sources would be required to report the designation of the type of site (*i.e.,* well site, centralized production facility, or compressor station) at which the fugitive emissions components affected facility is located. In addition, for each fugitive emissions components affected facility that becomes an affected facility during the reporting period, the date of the startup of production or the date of the first day of production after modification would be required for well sites or centralized production facility. Each fugitive emissions components affected facility at a well site would also be required to specify in the annual report what type of site it is (*i.e.,* a single wellhead only well site, small well site, a multi-wellhead only well site, or a well site with major production and processing equipment).

For fugitive emissions components affected facilities complying with the requirement to conduct surveys using AVO, the annual report would require the date of the survey, the total number and type of equipment for which leaks were identified, or, if no leaks were detected, a statement that there were no leaks on the day of inspection, the total number and type of equipment for which leaks identified were repaired within 15 calendar days, the total number and type of equipment for which no repair attempt was made within 15 days of the leaks being identified, and the total number and type of equipment placed on the delay of repair.

For fugitive emissions components affected facilities complying with the requirement to monitor for fugitive emissions using OGI on a semiannual or quarterly basis, the following information would be required to be included in the annual report:

- Date of the survey,
- Monitoring instrument used,
- Any deviations from key monitoring plan elements or a statement that there were no deviations from these elements of the monitoring plan,
- Number and type of components for which fugitive emissions were detected,
- Number and type of fugitive emissions components that were not repaired,
- Number and type of fugitive emission components (including designation as difficult-to-monitor or unsafe-to-monitor, if applicable) on delay of repair and explanation for each delay of repair, and
- Date of planned shutdown(s) that occurred during the reporting period if there are any components that have been placed on delay of repair.

b. EG OOOOc

In section XII.A.2 of the November 2021 proposal preamble (86 FR 63196; November 15, 2021), the EPA proposed BSER for EG OOOOc for reducing methane emissions from existing well sites that was the same as that proposed for new well sites, with a site-wide emissions threshold used to determine OGI monitoring frequency. However, as explained for new, modified, and reconstructed well sites and centralized production facilities in the previous section, the EPA has changed approaches for evaluating the BSER for fugitive emissions components, which also affects the determinations for BSER for existing sources under EG OOOOc.

The EPA did not identify any factors specific to existing sources that would alter the analysis performed for new sources to make that analysis different for existing well sites. Therefore, the EPA has evaluated the presumptive standards in EG OOOOc using the same approach as that for the proposed standards in NSPS OOOOb, specifically evaluating both the total cost-effectiveness of each monitoring option against a baseline of no monitoring and the incremental costs of increasing stringency between monitoring options. The EPA has determined that the methods for identifying fugitive emissions (*i.e.,* AVO, OGI, and EPA Method 21), methane emissions reductions, costs, and cost effectiveness related to the single pollutant approach for methane emissions discussed above for the fugitive emissions components affected facility at new well sites are also applicable for the fugitive emissions components affected facility at existing well sites. Further, the fugitive emissions requirements do not require the installation of controls on existing equipment or the retrofit of equipment, which can generally be an additional factor for consideration when determining the BSER for existing sources. Therefore, the EPA is proposing that it is appropriate to use the analysis developed for the proposed NSPS OOOOb to also determine the BSER and proposed presumptive standards for the EG OOOOc. Additionally, the EPA is proposing the same requirement that thief hatches must be closed and sealed at all times, in addition to the requiring fugitive emissions monitoring continue until all of the wells at an existing well site or centralized production facility are permanently closed and the owner or operator has completed the same requirements for well closure and submitted a well closure report meeting the same requirements described for new sources.

Single wellhead only and small well sites. Table 15 summarizes the costs associated with AVO inspections at existing single wellhead only well sites and existing small well sites. Based on the information summarized in Table 15, and the explanation provided for new single wellhead only well sites and new small well sites, the semiannual, quarterly, and bimonthly inspection frequencies are all reasonable. When examining the incremental costs of going from quarterly to bimonthly AVO inspections, the costs are not reasonable at $3,618/ton methane. Therefore, the EPA proposes that the BSER for existing single wellhead only well sites is quarterly AVO inspections, and the BSER for existing small sites includes quarterly AVO inspections and the closed and sealed requirement for thief hatches (as explained in the discussion above on new, modified and reconstructed small well sites).

TABLE 15—SUMMARY OF METHANE EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: AVO INSPECTIONS AT EXISTING SINGLE WELLHEAD ONLY WELL SITES AND SMALL WELL SITES

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	Total cost-effectiveness ($/ton methane)	Incremental cost-effectiveness ($/ton methane)
Annual	$296	0.11	$2,579	
Semiannual	417	0.40	1,048	429
Quarterly	660	0.56	1,181	1,511
Bimonthly	904	0.63	1,443	3,618
Monthly	1,633	0.69	2,367	11,455

Multi-wellhead only well sites. Table 16 summarizes the costs associated with OGI monitoring at multi-wellhead only well sites and Table 17 summarizes the costs associated with combined OGI and AVO surveys at multi-wellhead only well sites. Based on the information summarized in Table 16, the costs of annual, semiannual, quarterly, and bimonthly OGI monitoring is reasonable when compared to a baseline of no monitoring. When examining the incremental costs of going from semiannual OGI to quarterly OGI, the costs are not reasonable at $2,620/ton methane reduced. The EPA next evaluated the costs associated with adding AVO inspections to semiannual OGI monitoring to determine if additional emission reductions could be achieved at a reasonable cost. Based on the information summarized in Table 17, all programs presented are cost-effective when compared to a baseline of no monitoring. When examining the incremental costs of going from a combined program of semiannual OGI with quarterly AVO inspections to one with bimonthly AVO inspections, the costs are not reasonable at $3,394/ton methane reduced. Because the combined program of semiannual OGI with quarterly AVO inspections is cost-effective and would result in more visits to the well site, and thus provide opportunity to address any emissions detected, the EPA is proposing that the BSER for existing multi-wellhead only well sites is a combined program of semiannual OGI with quarterly AVO inspections.

TABLE 16—SUMMARY OF EMISSION REDUCTIONS AND COST-EFFECTIVENESS: OGI MONITORING AT WELL SITES WITH TWO OR MORE WELLHEADS

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	Total cost-effectiveness methane ($/ton)	Incremental cost-effectiveness methane ($/ton)
Baseline		2.66		
Annual	$1,972	1.18	$1,677	
Semiannual	2,327	1.79	1,300	578
Quarterly	3,037	2.06	1,473	2,620
Bimonthly	3,747	2.15	1,741	7,799
Monthly	5,877	2.24	2,619	23,140

TABLE 17—SUMMARY OF METHANE EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: COMBINED OGI MONITORING AND AVO INSPECTIONS AT EXISTING MULTI-WELLHEAD ONLY WELL SITES

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	Total cost-effectiveness methane ($/ton)	Incremental cost-effectiveness methane ($/ton)
Semiannual OGI	$2,327	1.79	$1,300	
OGI + Quarterly AVO	2,651	1.99	1,331	$1,606
OGI + Bimonthly AVO	2,973	2.09	1,425	3,394
OGI + Monthly AVO	3,671	2.16	1,822	12,728

Well sites with major production and processing equipment and centralized production facilities. Table 18 summarizes the costs associated with OGI monitoring and Table 19 summarizes the costs of combined OGI and AVO surveys at existing well sites and centralized production facilities with major production and processing equipment. The EPA is proposing the same definition for these well sites, including the specific equipment that constitutes a well site in this subcategory (*e.g.,* leak-prone equipment, such as controlled storage vessels). Based on the information summarized in Table 18, all monitoring frequencies appear cost-effective when compared to a baseline of no monitoring. When incremental costs are considered, the costs of going from quarterly to bimonthly OGI monitoring is not reasonable. The EPA then evaluated if AVO inspections could be added to the quarterly OGI monitoring at a reasonable cost. As shown in Table 19, all programs presented are cost-effective when compared to a baseline of no monitoring. When examining the incremental costs of going from a quarterly OGI program to a combined program of quarterly OGI with bimonthly AVO inspections, the costs are not reasonable at $2,497/ton methane reduced. Therefore, the EPA is proposing quarterly OGI monitoring for these sites. In sum, the EPA is proposing that the BSER for existing well sites with major production and processing equipment and centralized production facilities consists of quarterly OGI monitoring and the closed and sealed requirement for thief hatches (as explained above in the discussion on new, modified or reconstructed small well sites).

TABLE 18—SUMMARY OF EMISSION REDUCTIONS AND COST-EFFECTIVENESS: OGI MONITORING AT WELL SITES WITH MAJOR PRODUCTION OR PROCESSING EQUIPMENT

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	Total cost-effectiveness methane ($/ton)	Incremental cost-effectiveness methane ($/ton)
Baseline		8.51		
Annual	$2,162	3.99	$542	
Semiannual	2,588	5.73	452	$244
Quarterly	3,440	6.61	520	969
Bimonthly	4,292	6.97	616	2,398
Monthly	6,848	7.26	943	8,676

TABLE 19—SUMMARY OF METHANE EMISSIONS REDUCTIONS AND COST-EFFECTIVENESS: COMBINED OGI MONITORING AND AVO INSPECTIONS AT EXISTING WELL SITES WITH MAJOR PRODUCTION AND PROCESSING EQUIPMENT AND CENTRALIZED PRODUCTION FACILITIES

Monitoring frequency	Annual cost ($/yr/site)	Methane emission reduction (tpy/site)	Total cost-effectiveness methane ($/ton)	Incremental cost-effectiveness methane ($/ton)
Quarterly OGI	$3,440	6.61	$520	
OGI + Bimonthly AVO	4,232	6.93	611	$2,497
OGI + Monthly AVO	5,021	7.10	707	4,616

2. OGI Monitoring at Compressor Stations

a. NSPS OOOOb

In the November 2021 proposal, the EPA proposed that compressor stations would be required to conduct quarterly OGI or EPA Method 21 monitoring. Where OGI monitoring was used to perform the quarterly monitoring surveys, the EPA proposed surveys would be conducted according to the procedures proposed in the November 2021 proposal as appendix K.

In this supplemental proposal, the EPA is retaining the proposed quarterly OGI (or EPA Method 21) monitoring requirement for fugitive emissions components affected facilities located at compressor stations (including the requirement that consecutive quarterly monitoring survey be conducted at least 60 days apart). Also, as in the November 2021 proposal, the supplemental proposal includes the provision in the 2016 NSPS OOOOa that the quarterly monitoring may be waived when temperatures are below 0 °F for two of three consecutive calendar months of a quarterly monitoring period.

In addition, the EPA is proposing to add a requirement to conduct monthly AVO monitoring at compressor stations. As discussed above for well sites, the EPA finds these AVO monitoring requirements can be conducted by any personnel at the site as indications of emissions can be identified without the need for specialized training. Any indications of fugitive emissions identified via AVO would be subject to repair. The EPA specifically received comments on the November 2021 proposal that indicated that ''even though small company compressor stations are not manned 24 hours a day, they are visited weekly, if not daily.'' [80] Therefore, no additional costs are associated with the proposed monthly AVO inspection requirement for compressor stations.

While the EPA is maintaining (and strengthening in the case of the monthly AVO requirement) the November 2021 proposal as it relates to the collection of fugitive emissions components located at compressor stations, the EPA is not including the requirement to conduct OGI monitoring surveys according to the procedures that would become appendix K. See discussion in section IV.A.1.a.ii on comments received opposing this requirement. Instead, the EPA is proposing that quarterly surveys be performed according to the OGI procedures specified in the proposed regulatory text in NSPS OOOOb or according to EPA Method 21.

b. EG OOOOc

Based on the analysis presented in section XII.A.2 of the 2021 November proposal preamble (86 FR 63196; November 15, 2021), the proposed BSER for EG OOOOc for reducing methane emissions from existing compressor stations was quarterly monitoring (using either OGI or EPA Method 21).

Based on the same public comment considerations and reasoning as explained above (see sections IV.A.2.a.ii

[80] See Document ID Nos. EPA–HQ–OAR–2021–0317–0585 and EPA–HQ–OAR–2021–0317–0814.

of this preamble) for changes to the proposed NSPS OOOOb for fugitive emissions at compressor stations, the EPA is proposing the same changes and requirements under EG OOOOc. The EPA did not identify any factors specific to existing sources that would alter the analysis performed for new sources to make that analysis different for existing compressor stations. The EPA determined that the methods for identifying fugitive emissions (*i.e.,* AVO, OGI, and EPA Method 21), methane emission reductions, costs, and cost effectiveness discussed above for the fugitive emissions components affected facility at new compressor stations are also applicable for the fugitive emissions components affected facility at existing compressor stations. The fugitive emissions requirements do not require the installation of controls on existing equipment or the retrofit of equipment, which can generally be an additional factor for consideration when determining the BSER for existing sources. Therefore, the EPA found it is appropriate to continue using the analysis developed for the proposed NSPS OOOOb to also determine the BSER and proposed presumptive standards for the EG OOOOc.

3. OGI Monitoring at Well Sites and Compressor Stations on the Alaska North Slope

a. NSPS OOOOb

In the November 2021 proposal, the EPA proposed an annual monitoring requirement for well sites and compressor stations located on the Alaska North Slope, which included a requirement to follow the procedures outlined in the proposed appendix K where monitoring was conducted using OGI.

In this supplemental proposal, the EPA is retaining the proposed annual monitoring requirement for well sites and compressor stations located on the Alaska North Slope. Consecutive annual monitoring surveys would be required at least 9 months apart and no more than 13 months apart. For the reasons discussed in section IV.A.1.a.ii, the EPA is not including the requirement to follow the proposed procedures in appendix K when conducting monitoring surveys with OGI. The EPA is proposing that annual surveys be performed according to the OGI procedures specified in the proposed regulatory text in NSPS OOOOb or according to EPA Method 21 of appendix A–7 of this part.

b. EG OOOOc

Based on the analysis presented in section XII.A.2 of the November 2021 proposal preamble (86 FR 63196; November 15, 2021), the proposed BSER for EG OOOOc for reducing methane emissions from existing well sites and compressor stations located on the Alaska North Slope was annual monitoring.

In this supplemental proposal, the EPA is retaining the annual monitoring requirement for existing well sites and compressor stations located on the Alaska North Slope. As discussed in the November 2021 proposal, the same technical infeasibility issues with weather conditions exist for existing well sites and compressor stations located on the Alaska North Slope as for new well sites and compressor stations. Further, the EPA did not identify any other factors specific to existing sources located on the Alaska North Slope that would alter the analysis performed for new sources to make that analysis different for existing well sites and compressor stations. Therefore, the EPA is proposing a presumptive standard for reducing methane emissions from the fugitive emissions components designated facilities located at existing well sites and compressor stations located on the Alaska North Slope that is the same as what we are proposing for NSPS OOOOb.

B. Advanced Methane Detection Technologies

As discussed in section XI.A.5 of the November 2021 proposal preamble (86 FR 63175; November 15, 2021), the EPA proposed an alternative screening option that would allow the use of advanced measurement technologies as an alternative to the use of ground based OGI surveys and AVO inspections to identify emissions from the collection of fugitive emissions components located at well sites, centralized production facilities, and compressor stations. In the November 2021 proposal, the EPA stated that we did not have enough information to determine how the proposed alternative standard (*i.e.,* bimonthly screening using advanced measurement technologies) compared to the proposed BSER of OGI monitoring in that notice. Further we stated that information provided through comments to the November 2021 proposal may be used to reevaluate BSER for fugitive emissions components at well sites and compressor stations through a supplemental proposal.[81] As described below, commenters overwhelmingly supported the concept of an alternative screening option that would allow owners and operators to take advantage of advanced measurement technologies to detect fugitive emissions. Commenters also provided helpful information and input on how the alternative screening option could be made more useful and effective, including flexibilities that could be incorporated into the program design to enable the use of a wider variety of advanced measurement technologies. While there was widespread support of the concept of an alternative screening option, the EPA still does not have enough information to conduct the requisite BSER analysis[82] for any specific advanced measurement technology to determine whether it would qualify as the BSER for detecting fugitive emissions (either in lieu of or in addition to OGI). The EPA, however, does anticipate that through this alternative screening option, if finalized as proposed and utilized by the industry, the Agency would gain additional information that could be used to reevaluate the BSER in a future rulemaking.

In response to this feedback, the EPA is proposing a number of changes to the alternative screening option that are intended to support the deployment and utilization of a broader spectrum of advanced measurement technologies and, ultimately, enable more cost-effective reductions in emissions. These changes include a proposed ''matrix'' which would specify several different screening frequencies corresponding to a range of minimum detection levels, in contrast to the single screening frequency and detection level permitted under the November 2021 proposal. In addition, we are proposing to allow owners and operators the option of using continuous monitoring technologies as an alternative to periodic screening and are proposing long- and short-term emissions rate thresholds that would trigger corrective action as well as monitoring plan requirements for owners and operators that choose this approach.

Lastly, we are proposing to establish a clear and streamlined pathway for technology developers and other entities to seek the EPA's approval for the use of advanced measurement technologies under this alternative screening option. Under this pathway, entities would seek approval for alternative test methods to demonstrate the performance of

[81] 86 FR 63177 (November 15, 2021).

[82] Please see CAA section 111(a)(1) for a list of factors, including costs, that the EPA must take into account when determining whether an emission reduction system would qualify as the BSER.

alternative technologies, which would replace the use of OGI and AVO for fugitive emissions monitoring and the use of OGI for no identifiable emissions monitoring of covers and CVS (see section IV.K of this preamble) in both the proposed NSPS OOOOb and EG OOOOc. Once an alternative test method is approved by the EPA according to the proposed process, which is described in more detail below in Section IV.B.3, owners and operators would be able to utilize the advanced methane detection technology/technique in accordance with the alternative test method without the need for additional approval. Section IV.B.1 of this preamble discusses the use of advanced measurement technology in an alternative periodic screening approach. Section IV.B.2 of this preamble discusses the use of advanced measurement technologies in a continuous monitoring approach as a second alternative approach to the fugitive emissions monitoring and repair program and no identifiable emissions monitoring of covers and CVS in NSPS OOOOb and EG OOOOc. Section IV.B.3 of this preamble discusses the requirements for applying for an alternative test method, including who can submit an application for an alternative test method. Once an alternative test method is approved by the EPA, owners and operators would be able to utilize the advanced methane detection technology/technique in accordance with the alternative test method without the need for additional approval.

1. Alternative Periodic Screening

a. Summary of November 2021 Proposal

The EPA proposed an alternative fugitive emissions monitoring and repair program for new, modified, or reconstructed fugitive emissions sources (*i.e.,* collection of fugitive emissions components located at well sites, centralized production facilities, and compressor stations) that included bimonthly screening for large emissions events using advanced measurement technologies coupled with ground based OGI monitoring at least annually at each site. Specifically, the EPA proposed to allow owners and operators to comply with this alternative fugitive emissions standard instead of the ground-based quarterly or (co-proposed) semiannual OGI surveys for regulated sources, so long as owners and operators chose this alternative for all affected well sites, centralized production facilities, and compressor stations within a company-defined area and the methane detection technology used for the bimonthly screening surveys had a demonstrated minimum detection threshold of 10 kg/hr.

In the November 2021 proposal, the EPA sought comment on this minimum detection threshold for the advanced measurement technologies used in the alternative screening approach and solicited data on the current detection sensitivity of commercially available methane detection technologies as deployed, as well as other data that could be used to support consideration of a different minimum detection threshold. The EPA also solicited comment on development of a survey matrix for the alternative screening approach option, where instead of prescribing one detection threshold and screening frequency, the frequency of screening surveys would be based on the sensitivity of the technology (*i.e.,* screening surveys performed with technologies with the lower detection thresholds would need to be performed less frequently than screening surveys performed with technologies with higher detection thresholds).

The November 2021 proposal also included a requirement for owners and operators to include information specific to the alternative screening approach in their fugitive emissions monitoring plan. This would include information on which sites are utilizing this alternative screening option; a description of the measurement technology used for screenings; verification of the methane detection threshold, with supporting data to support the verification; procedures for daily verification of sensitivity under field conditions; standard operating procedures; and methodology for conducting the screening. The EPA solicited comment on when notifications would be required for sites where the alternative standard is applied and whether submission of the monitoring plan and/or Agency approval before utilizing the alternative standard was necessary to ensure consistency in screening survey procedures in the absence of finalized methods or procedures.

When fugitive emissions are detected through a periodic screening survey, the EPA proposed to require a ground based OGI survey of all fugitive emissions components at the site within 14 days of the screening survey. Due to the significance of the emissions events detected through screening, an expeditious timeframe was proposed, but the EPA requested additional information to fully evaluate the appropriateness of this proposed 14-day deadline for a follow-up OGI survey. Further, the EPA proposed to require repair of all fugitive emissions identified during the follow-up OGI survey in accordance with the same repair deadlines as those for regular fugitive surveys (*i.e.,* a first attempt at repair within 30 days of the OGI survey and final repair completed within 30 days of the first attempt). However, because large emissions events, especially those identified during the screening surveys, contribute disproportionately to emissions, the EPA solicited comment on creating a tiered repair deadline requirement that would be based on the severity of the fugitive emissions identified. The EPA also noted that some equipment types with large emissions warrant a requirement for a root cause analysis rather than simply requiring the equipment to be repaired and solicited comment on how a root cause analysis with corrective action approach could be applied in the proposed alternative screening approach.

b. Changes to Proposal and Rationale

The EPA received overwhelming support for the inclusion of an option to use advanced technologies for periodic screenings as an alternative to the fugitive emissions monitoring and repair program proposed in NSPS OOOOb and EG OOOOc. However, commenters remarked that the Agency failed to provide sufficient supporting evidence for the proposed minimum detection threshold of 10 kg/hr. Commenters provided alternative minimum detection thresholds and/or monitoring frequencies; many of these commenters provided supporting evidence for equivalency to the proposed fugitive emission monitoring and repair program in NSPS OOOOb and EG OOOOc, including results from LDAR program effectiveness models, such as FEAST. However, the results of these models varied widely, and as such, it was difficult to compare the different thresholds and frequencies presented by commenters. Additionally, one commenter suggested the EPA should investigate the role of modeling in equivalency demonstrations because the modeling outputs are highly impacted by the model inputs and assumptions made in the models.[83] Commenters also encouraged the EPA to adopt a survey matrix for the alternative screening approach option that would allow owners and operators to vary the frequency of periodic screening surveys based on the detection sensitivity of the screening survey technology. Commenters stated that the EPA should

[83] See Document ID No. EPA–HQ–OAR–2021–0317–0747.

use existing publicly available LDAR program effectiveness models [84] to determine a matrix of survey frequencies and detection thresholds that would provide a demonstration of equivalency between the alternative screening and the standard fugitive emissions monitoring and repair program.

Based on these comments and subsequent discussions with commenters,[85] the EPA decided that the best course of action for determining equivalency between different fugitive emission programs would be to run one of the leak detection and repair program effectiveness models with a set of standardized model inputs. For this effort, the EPA chose to conduct the modeling using FEAST so we could directly compare alternatives to the results of the OGI fugitive emissions program proposed as the BSER described in section IV.A of this preamble.[86]

Based on recent aerial and satellite studies,[87] [88] a primary advantage of more frequent screening with advanced technologies is to quickly identify large emission events (commonly referred to as ''super-emitters''). These super-emitters may be the result of large leaks from fugitive emissions components, but may also result from other sources, such as unlit flares or process malfunctions. Therefore, for this equivalency assessment, the EPA included emissions from other sources beyond fugitive emissions components that contribute to these super-emitters. This emissions distribution was developed using aerial study data from Cusworth, *et al.,*[89] and supplemented to include additional leaks between the lower limits of detection of the aerial surveys (about 15 to 20 kg/hr) and high-flow samplers commonly used in ground-level quantification studies (maximum quantification limit of about 9 kg/hr). The EPA assumed the small model plants (Model Plants 1 and 2) have one potential super-emitter source and that the larger model plant (Model Plant 4) has two potential super-emitter sources. The EPA evaluated the impact of different super-emitter frequencies but conducted the equivalency modeling using the 1.0 percent leak generation rate based on data from Zavala-Araiza, *et al.*[90] Additionally, the EPA performed a sensitivity analysis where we assumed a 1.0 percent leak generation rate for larger emissions sources commonly identified using aerial screening technologies (>26 kg/hr) and a 0.5 percent leak generation rate for fugitive emissions components consistent with the analysis for OGI and AVO programs described in section IV.A. More detail on the FEAST modeling assumptions and simulations is provided in the Supplemental TSD for this action located at Docket ID No. EPA–HQ–OAR–2021–0317. The EPA solicits comment on the use of LDAR effectiveness models in the development of the requirements for the alternative screening approach, specifically on the appropriateness of the inputs and assumptions used in the EPA's FEAST modeling simulations.

In this action, the EPA is revising the proposal for the alternative screening approach to provide additional flexibility to owners and operators to show that the advanced technology for which they are seeking approval would reduce fugitive emissions at least equivalent to the reduction under the proposed fugitive emission monitoring and repair program in NSPS OOOOb and EG OOOOc, as well as the proposed covers and CVS requirements in NSPS OOOOb and EG OOOOc. Instead of requiring a fixed screening survey frequency for all technologies, the EPA is proposing a survey matrix, where the minimum detection threshold of the screening technology determines the frequency of screening surveys and whether an annual OGI ground-based survey is needed as a supplement to the periodic screening surveys. Tables 20 and 21 present the details of the screening matrix for facilities required to conduct quarterly and semiannual OGI ground-based monitoring under the proposed fugitive emissions monitoring and repair program in NSPS OOOOb and EG OOOOc, respectively. Based on the FEAST modeling the EPA performed, technologies with a minimum detection threshold above 30 kg/hr could not be deemed equivalent to the proposed fugitive emissions monitoring and repair program in NSPS OOOOb and EG OOOOc at any screening survey frequency, even when coupled with an annual OGI ground-based survey. As such, the alternative periodic screening approach is limited to technologies with a minimum detection threshold less than or equal to 30 kg/hr.

TABLE 20—SURVEY MATRIX FOR ALTERNATIVE PERIODIC SCREENING APPROACH FOR AFFECTED FACILITIES SUBJECT TO QUARTERLY OGI MONITORING [a]

Minimum screening frequency	Minimum detection threshold of screening technology [b]
Quarterly + Annual OGI	≤1 kg/hr
Bimonthly	≤2 kg/hr
Monthly	≤4 kg/hr
Bimonthly + Annual OGI	≤10 kg/hr
Monthly + Annual OGI	≤30 kg/hr

[a] Well sites with major production and processing equipment, controlled storage vessels, natural gas-driven pneumatic controllers, associated covers and closed vent systems, and control devices, centralized production facilities, and compressor stations.

[b] Based on a probability of detection of 90 percent.

[84] Currently, the free publicly available simulation models are Fugitive Emissions Abatement Simulation Toolkit (FEAST) and Leak Detection and Repair Simulator (LDAR-Sim).

[85] See February 18, 2022, memorandum, *Summary of Meeting with American Petroleum Institute,* and February 28, 2022, memorandum, *Summary of Meeting with Environmental Defense Fund* located at Docket ID No. EPA–HQ–OAR–2021–0317.

[86] The EPA used FEAST version 3.1 to model the various programs. While the EPA used FEAST in this modeling exercise, the EPA would expect other available modeling simulation tools to produce similar results.

[87] Chen, Yuanlei, *et al.* 23 Mar 2022, *https://doi.org/10.1021/acs.est.1c06458.*

[88] Irakulis-Loitxate, Itziar, *et al.* 30 June 2021, *https://doi.org/10.1126/sciadv.abf4507.*

[89] Cusworth, Daniel, *et al.* 2 June 2021, *https://pubs.acs.org/doi/10.1021/acs.estlett.1c00173.*

[90] Zavala-Araiza, Daniel, *et al.* 16 Jan 2017, *https://doi.org/10.1038/ncomms14012.*

TABLE 21—SURVEY MATRIX FOR ALTERNATIVE PERIODIC SCREENING APPROACH FOR SINGLE AND MULTI-WELLHEAD ONLY SITES AND SMALL WELL SITES

Minimum screening frequency	Minimum detection threshold of screening technology [a]
Semiannual	≤1 kg/hr
Triannual	≤2 kg/hr
Triannual + Annual OGI	≤5 kg/hr
Quarterly + Annual OGI	≤15 kg/hr
Monthly + Annual OGI	≤30 kg/hr

[a] Based on a probability of detection of 90 percent.

These survey matrices will provide owners and operators who choose to implement the alternative periodic screening approach a wider selection of methane detection technologies from which to choose. The matrices also provide clear goals for vendors interested in the development of future technologies for methane detection. The EPA solicits comments on the survey matrices developed for the alternative periodic screening approach. Specifically, the EPA is interested in comments regarding the applicability of this matrix to both currently available technologies and those currently in development. Further, where specific technologies may not easily work within the context of the proposed matrix, we are soliciting detailed information on how those specific technologies work, including empirical data that would allow for additional evaluation of parameters in the proposed matrix; how emissions reduction equivalency can be demonstrated for those technologies compared with the standard OGI work practice; and changes that would be needed to the proposed matrix and the basis for those changes. Finally, we are soliciting feedback from owners and operators on ways to improve and further incentivize use of the proposed matrix approach to ensure they are comfortable utilizing any approved alternative technologies and test methods.

To reflect changes made to the proposed alternative periodic screening approach, the EPA is also modifying the proposed requirements for site-specific monitoring plans. The EPA is proposing to allow owners and operators to develop a site-specific monitoring plan or to develop a monitoring plan that covers multiples sites. At a minimum, the monitoring plan would need to contain the following information: (1) Identification of each site that will be monitored through periodic screening, including latitude and longitude coordinates; (2) identification of the test method(s) used for the periodic screening; (3) identification and contact information for the entity performing the periodic screening; (4) frequency for conducting periodic screenings; (5) procedures for conducting ground-based monitoring surveys in response to confirmed emission detection events from periodic screening surveys; (6) procedures and timing for identifying and repairing fugitive emissions components, covers, and CVS; (7) procedures and timing for verifying repairs for fugitive emissions components, covers, and CVS, and (8) recordkeeping and retention requirements.

The EPA is also clarifying the timeframes for when owners and operators must conduct the initial periodic screening survey when complying with the alternative periodic screening standard. In the November 2021 proposal, the EPA did not include timeframes for initiating periodic monitoring. The EPA is proposing that, for the initial periodic screening survey must be conducted within 90 days of the startup of production for each fugitive emissions components affected facility and/or storage vessel affected facility located at a new, modified, or reconstructed well site or centralized production facility and have not begun any fugitive monitoring; within 90 days of startup for each fugitive emissions components affected facility and storage vessel affected facility located at a new compressor station; and within 90 days of modification for each fugitive emissions components affected facility and storage vessel affected facility located at a modified compressor station. This 90-day initial screening requirement is the same as that required for the OGI-based fugitive emissions surveys. Additionally, the EPA is proposing that the initial periodic screening survey must be conducted no later than the date of the next required OGI fugitive emissions survey for any affected facility that was previously complying with the proposed fugitive emissions monitoring and repair program and proposed covers and CVS requirements in NSPS OOOOb and EG OOOOc. The EPA solicits comment on the proposed timing to perform the initial periodic screening survey, including information to support different timeframes.

When the periodic screening survey identifies emissions, the EPA is proposing to require a ground-based survey using OGI to identify the source of the emissions and any other fugitive emissions present. Any fugitive emissions identified during this ground-based survey would be subject to repair requirements. For fugitive emissions components, the EPA is proposing to require a completion of repairs within 30 days of the screening survey. The EPA is proposing that if the ground-based survey confirms that emissions were caused by a failure of a control device, the owner or operator must initiate a root cause analysis and determine appropriate corrective action within 24 hours of the ground-based survey. Because a failure of a control device would likely result in violations of the standards, the EPA is proposing appropriate corrective action should be taken as soon as possible to address these failures. Similarly, for covers and CVS, which are either fugitive components or are subject to the proposed cover and CVS requirements, the EPA is proposing to require repair within 30 days of the screening survey. The EPA is also proposing that if a leak or defect in a cover or CVS is identified, the owner or operator would be required to perform a root cause analysis to determine the cause of emissions from the cover or CVS within five days of completing the ground-based inspection, in addition to requiring repair within 30 days of the screening survey. The root cause analysis should include a determination as to whether the system was operated outside of the engineering design analyses and whether updates are necessary for the system. Because covers and CVS are required to be designed and operated with no identifiable emissions, indications of emissions from these sources could result in violations of the CVS requirements where the CVS is not a fugitive emissions component. Therefore, the EPA is proposing that appropriate corrective actions should be taken to resolve the emissions and ensure that the no detectable emissions standard is continuously met. Examples of corrective actions might include replacement of gaskets with a material more suitable for the composition of materials in the storage vessel or redesign of the entire CVS to ensure pressure setpoints are appropriate for relief devices on storage vessels. The EPA understands that the length of time necessary to complete corrective actions will vary based on the specific action taken. Therefore, we are soliciting comment on an appropriate deadline by which all corrective actions should be completed that would account for variability in complexity for such actions.

2. Alternative Continuous Monitoring Systems

a. Summary of November 2021 Proposal

In the November 2021 proposal, the EPA recognized that the alternative screening approach as outlined above may not be well suited to continuous monitoring technologies, such as sensors or open-path technology, even though these technologies may meet the minimum methane detection threshold (86 FR 63176; November 15, 2021). To incentivize these continuous monitoring technologies, which could be valuable tools in quickly detecting large emissions events, as well as identifying when emissions at the site begin to rise, the EPA requested information that could be used in an equivalence demonstration and would allow for the development of a flexible framework that could cover multiple types of continuous monitoring technologies and be used as a second alternative approach to the fugitive emissions monitoring and repair program in NSPS OOOOb and EG OOOOc. Specifically, the EPA requested information on the number of continuous monitors needed on a site, placement criteria for these monitors, response factors, minimum detection levels, frequency of data readings, how to interpret the monitor data to determine the difference between detected emissions and baseline emissions, how to determine allowable emissions versus leaks, the meteorological data criteria, measurement systems data quality indicators, calibration requirements and frequency of calibration checks, how downtime should be handled, and how to handle situations where the source of emissions cannot be identified even when the monitor registers a leak.

b. Changes to Proposal and Rationale

In response to the solicitation for comment on the development of a framework for continuous monitoring technologies in the November 2021 proposal, the EPA received comments from vendors, trade groups, industry, and environmental groups in support of developing a framework for these technologies. Many of these commenters discussed the benefits of continuous monitoring systems including the low detection sensitivities of the technologies, the potential savings involved in identifying the largest leaks in near real time, and the potential to repair leaks on a much quicker timeframe. The EPA is proposing a framework for continuous monitoring technologies that is akin to the fenceline monitoring work practice promulgated by the EPA in 2015 as part of the National Emissions Standards for Hazardous Air Pollutants (NESHAP) for the petroleum refinery sector (80 FR 75178; December 1, 2015). Under this proposed approach, an owner or operator utilizing continuous monitoring technologies would conduct a root cause analysis and corrective action whenever a methane emission rate action-level is exceeded at the boundary of a facility.

The EPA is proposing methane emissions rate (*i.e.,* kg/hr) based action levels instead of methane concentration (*e.g.,* ppmv) based action levels (as in the Refineries NESHAP) in order to: (1) Account for upwind contributions from other sites and meteorological effects and (2) allow the Agency to evaluate the methane emissions reductions achieved by this framework, thus providing for a metric to demonstrate equivalency with the proposed fugitive emissions monitoring and repair program and proposed covers and CVS requirements in NSPS OOOOb and EG OOOOc. Through the comments received and subsequent discussions with commenters,[91] the EPA has gathered information on how these continuous monitoring systems have been applied and how owners and operators use the information from these systems to initiate a response to identify and repair leaks. The application of these systems appears to vary widely across the industry, with no consistent standard currently employed. This is especially true for how sources initiate identification of the cause of a leak. To standardize the use of these systems across the industry, the EPA is proposing two action levels in this alternative continuous monitoring approach: (1) A long-term action level to limit emissions over time and (2) a short-term action level to identify large leaks and malfunctions. Both action levels would apply to all owners and operators choosing to use this alternative, and a root cause analysis and corrective action would be triggered when either action level is exceeded. The proposed long-term action levels are developed from the same FEAST Model used for the development of the proposed survey matrix for periodic screening and the action-levels are based on the annual emissions (including super-emitters) of our Model Plant 2 and Model Plant 3 discussed in section IV.A.2 of this preamble. Based on this data, the EPA is proposing an action-level of 1.2 kg/hr[92] for sites consisting of only wellheads and 1.6 kg/hr[93] for all other well sites and compressor stations with equipment. This long-term action level would be based on a rolling 90-day average, where the 90-day average would be recalculated each day. The EPA is also proposing a short-term action-level of 15 kg/hr for sites consisting of only wellheads and 21 kg/hr for other well sites and compressor stations. These action levels are based on the same magnitude of emissions as the long-term action level; however, the rates are defined over the period of seven days. The short-term action level would be based on a rolling 7-day average, where the 7-day average would be recalculated each day. The EPA solicits comment on the proposed short-term and long-term action levels. The EPA is also aware of industry led efforts[94] to minimize methane emissions through the entirety of the value chain using the percentage of intensity or production as a metric. The EPA is soliciting comment on the potential use of intensity or production in the development of action levels, including appropriate thresholds for setting such action levels on both a short-term and long-term basis.

The EPA is aware of other continuous monitoring systems using technologies that are not designed to quantify a site-level methane emissions rate (*e.g.,*

[91] See memorandum, *Summary of Meetings on Alternative Screening and Continuous Monitoring Systems* located at Docket ID No. EPA–HQ–OAR–2021–0317.

[92] 11.6 tons per year methane.

[93] 15.5 tons per year methane.

[94] One Future Coalition.

camera based continuous systems). While the EPA believes these systems could be useful in a methane mitigation program, they are not suitable for the proposed alternative continuous monitoring approach because they are not capable of quantifying site-level methane emissions, which is the basis for the equivalency demonstration of the proposed alternative continuous monitoring approach. That said, the EPA solicits comment on how these types of systems could fit within the alternative continuous monitoring approach, what action levels should be applied to a non-emission rate based continuous monitoring system, and data to support those action levels in order to conduct an equivalency demonstration. The EPA also solicits comment on whether a different type of approach should be used for these other types of continuous monitoring systems, and if so, what that approach would look like and how equivalency could be demonstrated between the approach and the proposed fugitive emissions monitoring and repair program and proposed covers and CVS requirements in NSPS OOOOb and EG OOOOc.

The EPA is proposing that owners and operators must initiate a root cause analysis within 5 calendar days of an exceedance of either the short-term or long-term action level. Additionally, the EPA is proposing that the initial corrective action identified must be completed within five calendar days of an exceedance of the short-term action level and within 30 calendar days of an exceedance of the long-term action level. If, upon completion of the initial corrective actions, the continuous monitor readings remain above an action level, or if all identified corrective action measures require more than 30 days to complete, the owner or operator would be required to develop a corrective action plan and submit it to the Administrator within 60 calendar days of the initial action level exceedance. The EPA is soliciting comment on the proposed requirements for the root cause analysis and corrective action, the timeframes for conducting these activities, and the requirement for corrective action plan submittals.

In order to ensure that the continuous monitoring systems used in the alternative continuous monitoring approach are sensitive enough to trigger at the proposed action levels, the EPA is proposing that the continuous monitoring systems must have a detection level an order of magnitude less than the proposed action level and that the system must produce a valid mass emissions rate (*i.e.,* kg/hr) from the site at least once every twelve hours. The EPA is also proposing requirements related to operability of the monitors within the continuous monitoring system. Specifically, the EPA is proposing that the operational downtime of the continuous monitoring system, or the time that any monitor fails to collect or transmit quality assured data, must be less than or equal to 10 percent on a 12-month rolling average, where the 12-month average is recalculated each month. We are soliciting comment on this approach to addressing downtime and other ways to address system downtime and the consequences of that downtime.

Similar to the alternative periodic screening approach, owners and operators who choose to implement the alternative continuous monitoring approach must develop a monitoring plan. The monitoring plan can either be a site-specific monitoring plan or cover multiples sites. At a minimum, the monitoring plan would need to contain the following information: (1) Identification of each site that will be monitored through periodic screening, including latitude and longitude coordinates; (2) identification of the test method(s) used for the continuous monitoring; (3) identification and contact information for the entity performing the continuous monitoring if the continuous monitoring system is administered through a third-party provider; (4) number and location of monitors; (5) system calibration procedures and schedules; (6) identification of critical components and procedures for their repairs; (7) procedures for out of control periods; (8) procedures for determining when a fugitive emissions event is detected by the continuous monitoring technology; (9) procedures and timing for identifying and repairing fugitive emissions components, covers, and CVS; (10) procedures and timing for verifying repairs for fugitive emissions components, covers, and CVS, and (11) recordkeeping and retention requirements.

The EPA is proposing that owners and operators who choose to comply with the alternative continuous monitoring approach must install and begin conducting monitoring with the continuous monitoring system within 120 days of the startup of production for each fugitive emissions components affected facility or storage vessel affected facility located at a new, modified, or reconstructed well site or centralized production facility; within 120 days of startup for each fugitive emissions components affected facility and storage vessel affected facility located at a new compressor station; and within 120 days of modification for each fugitive emissions components affected facility and storage vessel affected facility located at a modified compressor station. Additionally, the EPA is proposing the continuous monitoring system must begin monitoring no later than the date of the next scheduled OGI monitoring survey for any affected facility that was previously complying with the proposed fugitive emissions monitoring and repair program and proposed covers and CVS requirements in NSPS OOOOb and EG OOOOc. The EPA solicits comment on the proposed timing to install and begin conducting monitoring with the continuous monitoring system, including information to support different timeframes.

The EPA is soliciting comment on this proposed alternative continuous monitoring approach, especially the use of site-level methane emissions as a surrogate for VOC emissions, the practicality of implementing the proposed framework, and any additional data on how continuous monitoring technologies have been deployed at well sites, centralized production facilities, and compressor stations. The EPA proposes to use the continuous monitoring system to confirm the effectiveness of the corrective action and has proposed additional repair and notification requirements for when corrective action is delayed or when the corrective action is ineffective.

3. Alternative Test Method Approval

a. Summary of November 2021 Proposal

The EPA solicited comment on whether owners and operators choosing to comply with the alternative periodic screening approach would need to submit their monitoring plan to the delegated authority and whether Agency approval was necessary before the owner or operator could implement the alternative. The EPA proposed that EPA approval may be necessary to ensure consistency in screening survey procedures in the absence of finalized methods and procedures.

b. Changes to Proposal and Rationale

The EPA received comments from industry, state agencies, and non-governmental organizations acknowledging that review and approval of individual monitoring plans increases the burden on industry. Additionally, the review of these monitoring plans increases the burden on delegated authorities to evaluate the alternative technologies and may result in inconsistent application or variable approvals for the same technology between different states. The EPA also received direct comment [95] from one state that expressed that the EPA should serve as the clearinghouse for approving these advanced measurement techniques.

The EPA continues to find that, prior to implementation, approval of the technologies used in the alternative periodic screening approach and the alternative continuous monitoring approach is necessary due to the lack of standard methods and performance specifications for these types of systems. Approval of these systems will allow a wider range of methane detection techniques to be applied, but also allow the Agency to provide more specific guidance on the proper operation of these systems. Based on the comments received, the EPA is proposing to require these systems to be approved by the Administrator under the alternative test method provisions in 40 CFR 60.8(b)(3) instead of owners and operators seeking approval of these systems through site-specific monitoring plans. The use of the alternative test method provisions has typically been applied to the approval of alternative test methods used to conduct performance testing to demonstrate compliance with a numerical emission standard. While work practice standards are not numerical emission standards, there is precedent for approving alternative test methods within work practice standards, so long as the change in the testing or monitoring method or procedure will provide a determination of compliance status at the same or higher stringency as the method or procedure specified in the applicable regulation.[96] [97] The EPA is soliciting comment on the use of this provision at 40 CFR 60.8(b)(3) for the approval of the alternative test method for an alternative technology for measurements within the proposed alternative periodic screening approach and the proposed alternative continuous monitoring approach.

Once an alternative test method for an alternative technology has been approved, if it is broadly applicable, the EPA will post it to the Emission Measurement Center website.[98] Any owner or operator who meets the specific applicability for the alternative test method, as outlined in the alternative test method, may use the alternative test method to comply with the alternative periodic screening approach or alternative continuous monitoring approach. The owner or operator would be required to notify the Administrator of adoption of the alternative periodic screening approach or alternative continuous monitoring approach in the first annual report following implementation of the alternative standard. The owner or operator's fugitive emissions monitoring plan would identify the approved alternative test method(s) the owner or operator is using the alternative periodic screening approach or alternative continuous monitoring approach.

In an effort to streamline the approval process and reduce the time needed for processing these request for alternative test methods, the EPA is proposing the following pre-qualifications for those requesting approval of their technology: (1) Requestors are limited to any individual or organization located in or that has representation in the U.S.; (2) requestor must have direct knowledge of the design, operation, and characteristics of the underlying technology; (3) the underlying technology must have been applied to methane measurements in the oil and gas production, processing, and/or transmission and storage sectors either domestically or internationally; (4) the technology must be a commercial product, meaning it has been sold, leased, or licensed, or offered for sale, lease, or license, to the general public. While the EPA has based these pre-qualifications on comments received from vendors or advanced methane detection technologies, the EPA solicits comments on how we have characterized the pre-qualifications in this proposal and whether any additional pre-qualifications may be appropriate.

In an effort to streamline the approval of these requests by ensuring adequate information is received in the request to allow a full evaluation of the alternative technology, the EPA is proposing that any application for an alternative test method contain the following information at a minimum: (1) The desired applicability of the technology (*i.e.,* site-specific, basin-specific or broadly applicable across the sector); (2) a description of the measurement systems; (3) supporting information verifying that the technology meets the desired detection threshold(s) as applied in the field; (4) a detailed description of the alternative testing procedure(s), including data quality objectives to ensure the detection threshold(s) are maintained and procedures for a daily verification check of the measurement sensitivity under field conditions, and; (5) standard operating procedures consistent with the EPA's guidance and including safety considerations, measurement limitations, personnel qualification/responsibilities, equipment and supplies, data and record management, and quality assurance/quality control. The EPA solicits comment on the proposed information required to be submitted with the application of an alternative test method and whether the EPA should consider requiring any additional information.

The EPA is proposing a defined timeframe for review and determination of alternative test method requests by the Agency. The EPA is proposing to issue either an approval or disapproval in writing to the requestor within 270 days of receipt of the request, with a number of milestones for acknowledgement of receipt and initial reviews. The EPA is also proposing a mechanism to allow a conditional approval of a submitted alternative test method in the event a determination is not made by the Agency within 270 days. Finally, the EPA is maintaining the authority to rescind any previous approval if we find it reasonable to dispute the results of any alternative test method used to demonstrate compliance with either the alternative periodic screening approach or the alternative continuous monitoring approach. The EPA proposes to make these approvals and the supporting information available to the public on an EPA supported website. The EPA solicits comments on the proposed timeframe to review and approve alternative test methods and whether alternative timelines should be considered.

C. Super-Emitter Response Program

Although results vary by basin, many studies have found that the top five percent of sources contribute over 50 percent of the total emissions.[99] There is

[95] See Document ID No. EPA–HQ–OAR–2021–0317–0763.

[96] In amendments to the approval of state programs and delegation of federal authorities, the EPA clarified that certain provisions within work practices, such as those related to compliance and enforcement provisions, are delegable provisions. In particular, the EPA stated that monitoring requirements are delegable. See 65 FR 55810 (September 14, 2000).

[97] The fenceline monitoring work practice in 40 CFR part 63 subpart CC allows owners and operators to seek an alternative test method for use of technologies other than the prescribed sorbent tube monitoring with Method 325 A and B of appendix A to 40 CFR part 63. See 40 CFR 63.658(k)(1).

[98] *https://www.epa.gov/emc/oil-andgas-approved-alternative-test-methods.*

[99] Yuanlei Chen *et al.,* ''Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey,'' *Environmental Science and Technology,* Vol. 56, No. 7 (March 2022), *https://doi.org/10.1021/acs.est.1c06458.*

wide agreement in the peer-reviewed research that a subset of sources comprising the very largest emission events, commonly referred to as super-emitters, is typically caused by abnormal operating conditions or malfunctions.[100]

Many of the requirements of this rule, when implemented correctly, would result in reducing the number of super-emitter emissions events. For the reasons described below, the EPA is further proposing a super-emitter response program as a backstop to address the large contribution of super-emitters to the pollution from this sector. For purposes of this program, the EPA is proposing to define a super-emitter emissions event as quantified emissions of 100 kg/hr or greater of methane, a very high threshold that encompasses the largest emissions events.

Recognizing that super-emitter emissions events are a significant source of methane and VOC emissions, the November 2021 proposal and this supplemental proposal contain standards and requirements that, if implemented correctly, would prevent (*e.g.,* via zero-emissions standards for pneumatic controllers and design and operation requirements for flares) or detect and mitigate (*e.g.,* via regular monitoring for fugitive emissions using OGI or advanced detection technologies) most of these large emissions events.[101] We note that the estimated emission reductions in both the November 2021 proposal and this supplemental proposal likely undercount the emission reductions that would be achieved by this rule because they might not fully account for the emissions resulting from all super-emitter emissions events that would be prevented or quickly corrected as a result of this rule. Though we are not currently able to quantify the emissions reductions likely to result from preventing or more quickly mitigating super-emitter emissions events, we note that the information presented in appendix D to the RIA for this supplemental proposal includes model simulations suggesting that covering large emitters could ''significantly impact[] the expected emissions from the fugitive emission program.'' [102]

It is clear from the estimates from the two proposals that these methods are expected to result in the prevention, detection, and repair of many current super-emitters. Sites that take advantage of opportunities for continuous emissions monitoring offered by the alternative monitoring strategies the EPA has proposed may be particularly able to quickly identify and timely address these events.

However, super-emitters' significant impact on the communities where they are located, as well as their greatly disproportionate contribution to emissions in total, call for additional measures to backstop compliance and address the unique characteristics of these events. The abnormal process conditions that characterize these events can be persistent or episodic, meaning that while some sources are consistent super-emitters, many such large emissions events are intermittent and can occur at different sites over time.[103] A cost-effective inspection program can therefore miss some of these super-emitter events, even if implemented in accordance with the proposed standards. We further note that oil and gas facilities, in particular those in remote areas, may not have personnel present when super-emitter emissions events occur. Given the large number and broad geographic distribution of affected sources and designated facilities to be regulated under this rule, the EPA also recognizes that the need for rigorous compliance assurance will be particularly important in this source category.

The same sophisticated research and constantly advancing new monitoring technologies that have contributed to our understanding of the serious problem of super-emitters can bolster the other standards and requirements included in this proposal and serve to help identify and mitigate any super-emitter emissions events. The super-emitter response program, which the EPA outlined conceptually in the November 2021 proposal for public comment and which we are now proposing here, would allow the use of reliable and demonstrated remote sensing technology deployed by experienced, certified entities or regulatory authorities to find these large emissions sources. As described in the November 2021 proposal, this proposed super-emitter response program builds on the growing use of these advanced technologies by a variety of entities to identify and mitigate super-emitting events.

This proposed program establishes a pathway by which an EPA-approved entity or regulatory authority may provide credible, well-documented identification of a super-emitter emissions event using one of several permitted technologies and approaches, and then notify the responsible owner or operator. Once notified of the event, owners and operators would be required to perform a root-cause analysis and take corrective actions to address the emissions source at their individual well sites, centralized production facilities, and compressor stations. Upon conducting the root-cause analysis, the owner or operator may determine that all necessary and appropriate actions have been taken and that no additional action is needed. However, if the owner or operator confirms the existence of a super-emitter emissions event that requires mitigation—either due to a failure to comply with one of the standards in this rule or due to an upset or malfunction at a source covered by this rule—then the owner or operator must take prompt steps to eliminate the super-emitter emissions event and report both its root-cause analysis and corrective actions to the EPA and the appropriate state or tribal authority. To ensure this program operates in a transparent manner, the EPA will make available in a document repository the notices to operators that the EPA receives, as well as the reports

[100] Daniel Zavala-Araiza *et al.,* ''Super-emitters in Natural Gas Infrastructure are Caused by Abnormal Process Conditions,'' *Nature Communications* Vol. 8 (January 2017), *https://doi.org/10.1038/ncomms14012;* Ramón A. Alvarez *et al.,* ''Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain,'' *Science,* Vol. 361 (July 2018), *https://doi.org/10.1126/science.aar7204;* Daniel H. Cusworth *et al.,* ''Intermittency of Large Methane Emitters in the Permian Basin,'' *Environmental Science and Technology Letters* Vol. 8, No. 7 (June 2021), *https://doi.org/10.1021/acs.estlett.1c00173;* Jeffrey S. Rutherford *et al.,* ''Closing the Methane Gap in US Oil and Natural Gas Production Emissions Inventories,'' *Nature Communications* Vol. 12 (August 2021), *https://doi.org/10.1038/s41467-021-25017-4;* Yuanlei Chen *et al.,* ''Quantifying Regional Methane Emissions in the New Mexico Permian Basin with a Comprehensive Aerial Survey,'' *Environmental Science and Technology,* Vol. 56, No. 7 (March 2022), *https://doi.org/10.1021/acs.est.1c06458.*

[101] Super-emitter emissions events could also be from intentional venting as part of normal operations or maintenance. The proposed super-emitter response program discussed in this section is not intended to address these events.

[102] As stated, some of the model simulations in appendix D to the RIA for this supplemental proposal suggest that large-emitters could significantly impact the estimated emissions reductions; however, those simulations are not directly related to the definition of ''super-emitter'' included in this proposal, thus the emissions and emission reductions cannot be used to directly assess the emissions or emission reductions related to the proposed super-emitter program. The model simulations relied on information of large emissions from a single basin (Permian), and available data suggest that the frequency of these events may vary significantly across different production basins, which could lead to significant uncertainty if the emission reductions were applied nationwide.

[103] Daniel Zavala-Araiza *et al.,* ''Super-emitters in Natural Gas Infrastructure are Caused by Abnormal Process Conditions,'' *Nature Communications* Vol. 8 (January 2017), *https://doi.org/10.1038/ncomms14012;* Daniel H. Cusworth *et al.,* ''Intermittency of Large Methane Emitters in the Permian Basin,'' *Environmental Science and Technology Letters* Vol. 8, No. 7 (June 2021), *https://doi.org/10.1021/acs.estlett.1c00173.*

sent to the EPA by owners and operators in response, so that notifiers, communities, and owners and operators have quick access to the information submitted to the EPA under the super-emitter provisions.

The EPA believes that the super-emitter response program proposed here will provide a cost-effective and efficient mechanism for comprehensively detecting and addressing super-emitter emission events, complementing and reinforcing the other requirements of this proposal and securing reductions in methane as well as emissions of VOCs and other health-harming air pollutants. In response to the November 2021 proposal, the EPA received comments from representatives of communities affected by air pollution from the oil and natural gas sector, including communities with environmental justice (EJ) concerns, voicing concern about the impacts of these emissions and support for enhanced monitoring efforts. The EPA anticipates that the proposed super-emitter response program will have important benefits for such communities and will create opportunities for communities to partner with entities engaged in remote sensing to monitor nearby sources of emissions. The EPA also anticipates that the proposed transparency requirements for notifications and for follow-up actions by owners and operators will provide valuable information for communities about neighboring sources of emissions and steps taken to mitigate them.

This section begins with a description of the November 2021 proposal and the comments received on that proposal, followed by a description of the specific criteria the EPA is proposing for notifications to sources of super-emitter events and subsequent corrective actions taken to eliminate the emissions. The EPA seeks comment on all aspects of this proposed program.

1. November 2021 Proposal

As described in the November 2021 proposal, ''industry, researchers, and NGOs have utilized advanced methane detection systems to quickly identify large emission sources and target ground based OGI surveys. state and local governments, industry, researchers, and NGOs have been utilizing advanced technologies to better understand the detection of, sources of, and factors that lead to large emission events.'' See 86 FR 63177 (November 15, 2021). In that proposal, the EPA solicited comment on a potential program for large emission events that would take advantage of data from the use of advanced technologies that could identify super-emitter emissions events; under the program, if emissions were detected above a defined threshold ''by a community, a Federal or state agency, or any other third party, the owner or operator would be required to investigate the event, do a root cause analysis, and take appropriate action to mitigate the emissions, and maintain records and report on such events.'' See 86 FR 63177 (November 15, 2021).

2. Rationale for and Summary of Proposed Program

The EPA received numerous comments from industry, non-industry groups, states, tribes, and local communities articulating a range of views on the concept described in the November 2021 proposal. These comments provided valuable information and input on, among other issues, the potential benefits of the program and the importance of comprehensively addressing large emission events; implementation challenges and concerns that would arise in establishing a system by which researchers or other third parties could identify these events and notify owners and operators, including concerns related to ensuring the accuracy of such notifications and providing for safe and lawful monitoring of sources; and the EPA's legal authority to promulgate such a program under CAA section 111.

The EPA has carefully considered these comments, in conjunction with various peer-reviewed studies, in designing this proposal for a super-emitter response program. As described below, the principal objective of this proposed program is to provide a comprehensive and effective remedy for large emission events that disproportionately contribute to methane emissions from the Crude Oil and Natural Gas source category and can be accompanied by health-harming pollution that affects nearby communities. However, as comments provided by a wide range of stakeholders emphasized, it is also imperative that any such program ensure the safety of entities engaged in monitoring as well as of owners and operators and their employees; utilize accurate, reliable, and rigorous methods for identifying large emission events; and be streamlined and efficient to administer, both for owners and operators of regulated sources as well as for the EPA and the states. The proposed program contains key features and safeguards that were designed with these principles in mind.

As noted above, the EPA assesses this *COM007*program is important both because of the significant harm associated with super-emitter emissions events and the well-documented challenges in identifying these events. The most widely known sources of unintentional releases resulting in super-emitter emissions events are from controlled tank batteries, flares, natural gas-driven pneumatic controllers, and fugitive emissions components. The standards and requirements included in the November 2021 proposed rule and this supplemental proposal are expected to identify and eliminate many super-emitters when implemented as required. However, a cost-effective inspection program requiring periodic fugitive emissions surveys cannot immediately detect every instance of a super-emitter emissions event or quickly identify when equipment malfunctions occur and therefore may not capture some intermittent or episodic super-emitter emissions events. Further, it is not cost-effective to impose additional inspection costs on every source in hopes of detecting the small percentage of sources that become super-emitters. The proposed super-emitter response program would provide a cost-effective backstop to the rest of the regulatory program by directing operator attention to problems urgently requiring a remedy and providing useful feedback about the effectiveness of the other regulatory requirements.

The EPA faced a similar situation when establishing standards for petroleum refineries, where cost-effective controls and inspections of equipment and operations would not have addressed potentially significant levels of emissions that could occur between regular inspections.[104] In that instance, the EPA required additional monitoring and corrective action to address such high emissions; specifically, the EPA required fenceline monitoring to ''identify a significant increase in emissions in a timely manner (*e.g.,* a large equipment leak or a significant tear in a storage vessel seal), which would allow corrective action measures to occur more rapidly than it would if a source relied solely on the traditional infrequent monitoring and inspection methods.'' 79 FR at 36920.[105] The EPA is taking a similar approach in this supplemental proposal to address super-emitter emissions events in a timely manner. This program

[104] *Proposed Rule: Petroleum Refinery Sector Risk and Technology Review and New Source Performance Standards,* 79 FR 36880, 36920 (June 30, 2014).

[105] This fenceline monitoring requirement is codified at 40 CFR 63.658 of the National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, 40 CFR part 63, subpart CC.

is likewise motivated by the same types of considerations that led the EPA to establish a hotline for reporting oil spills and other environmental releases (*e.g., https://www.epa.gov/emergency-response/national-response-center*). However, unlike most oil spills, large releases of methane are not visible to the human eye; identifying them requires people with specialized equipment and expertise.

The following sections first describe the details of the proposed super-emitter response program, including the definition of a super-emitter emissions event under the program, the requirements for any party that seeks to report a super-emitter emissions event under the program; and the requirements for owners and operators responding to such report. It then describes the statutory structure for the program under CAA section 111.

a. Super-Emitter Response Program Design

Threshold for a super-emitter emissions event. To clearly define what emissions events would be subject to the requirements of this program, the EPA is proposing to define a super-emitter emissions event as any emissions detected using remote detection methods with a quantified emission rate of 100 kg/hr of methane or greater. While the term ''super-emitter'' has been widely used to describe large emissions events in literature and various other discussions, no specific mass-based or production-based rates have been formally or consistently applied to the term. The EPA is proposing to apply a definition, for purposes of this response program, that focuses on very large emissions events at an individual well site, centralized production facility, compressor station, or natural gas processing plant which warrant immediate investigation.

This threshold definition of 100 kg/hr of methane takes into account several factors. First, this proposed super-emitter response program is intended to provide a mechanism to utilize high quality remote sensing detection of only the largest, most harmful emissions events, and not address all the standards and requirements of NSPS OOOOb and EG OOOOc that are applicable to individual affected facilities and associated controls. The goal of this program is to ensure that if, notwithstanding the other requirements in this proposal, a very large emissions event occurs and is detected by a regulatory authority or qualified third parties using particular technologies, that super-emitting event is quickly addressed. Therefore, the threshold definition of a super-emitter emissions event needs to be sufficiently high that it does not duplicate other actions (*e.g.,* leak detection and repair) facilities are undertaking to comply with the applicable standards in the rule. Second, where compliance is achieved with the applicable standards, the EPA does not expect unintentional releases at these very high levels to occur in normal operations. Thus, the occurrence of an unintentional release at this emissions rate should be unusual and would clearly warrant immediate investigation and mitigation. Defining a super-emitter event to encompass these unusually large events is therefore consistent with the EPA's objective of establishing a backstop to the other requirements proposed in this rule. Third, by setting such a high threshold to capture the largest and most concerning emissions events, the program would be more feasible to implement and would properly focus resources on the most significant and potentially harmful sources of emissions. Such high rates of emissions also mean that it is cost effective to quickly address these super-emitters, which release more methane in a single week than the total methane cost-effectively prevented over the course of an entire year at sources covered by the fugitive emissions program. Fourth, as discussed immediately below, this threshold allows the use of remote sensing technologies that are already in use by the EPA, states, and third parties, which could allow the program to be readily implemented upon finalizing NSPS OOOOb and the subsequent state plans required by EG OOOOc.

Technologies that may be used to detect a super-emitter emissions event. Various technologies are available for remote methane detection that would provide a quantified mass emissions rate, including several that would meet the performance criteria proposed for the alternative periodic screening or continuous monitoring for fugitive emissions as described in sections IV.B.1 and IV.B.2 of this preamble. Some commenters stated that thresholds should be defined that could allow the use of a range of technologies, without limiting to one specific class of technologies.[106] Among these, as discussed in the November 2021 proposal, the EPA described its understanding that ''some satellite systems are generally capable of identifying emissions above 100 kg/hr with a spatial resolution which could allow identification of emission events from an individual site.'' See 86 FR 63177 (November 15, 2021). Several commenters agreed that the use of satellites for detecting super-emitters was appropriate, while noting that this technology is continuing to advance.[107] Further, several commenters raised concerns regarding potential safety or trespassing on sites with a program using more ground based or close-range detection methods.[108]

The EPA agrees with the commenters that some flexibility is appropriate in the type of technology that could be utilized for the detection of super-emitters, provided that the technology can be safely deployed and will reliably identify super-emitter emissions events as defined in this proposal. Considering concerns for the safety of individuals engaged in third-party monitoring and of facility operator personnel, the purposes of this program as described above, and feedback from commenters on the performance and characteristics of various monitoring technologies, the EPA assesses that allowing only remote-sensing technologies is appropriate. Therefore, we are proposing to allow the use of remote-sensing aircraft, mobile monitoring platforms, or satellites to identify super-emitter emissions events. The EPA is soliciting comment on this list of technology types that could be applied for the identification of super-emitter emissions events and the threshold of 100 kg/hr of methane.

Qualifications and requirements for notification of super-emitter emissions events. Next, the EPA is proposing specific requirements related to the notification of a super-emitter emissions event by regulatory authorities and qualified third-party notifiers. Several commenters emphasized the importance of assuring the quality and reliability of the data and suggested that the EPA should have a role in verifying the information to provide that assurance.[109] In order to address concerns about the expertise of the third party identifying the super-emitter event, the EPA is proposing that any

[106] See Document ID Nos. EPA–HQ–OAR–2021–0317–0605, EPA–HQ–OAR–2021–0317–0769, EPA–HQ–OAR–2021–0317–0811, and EPA–HQ–OAR–2021–0317–0844.

[107] See Document ID Nos. EPA–HQ–OAR–2021–0317–0738, EPA–HQ–OAR–2021–0317–0753, EPA–HQ–OAR–2021–0317–0769, and EPA–HQ–OAR–2021–0317–1391.

[108] See Document ID Nos. EPA–HQ–OAR–2021–0317–0727, EPA–HQ–OAR–2021–0317–0730, EPA–HQ–OAR–2021–0317–0749, EPA–HQ–OAR–2021–0317–0750, EPA–HQ–OAR–2021–0317–0763, EPA–HQ–OAR–2021–0317–0797, EPA–HQ–OAR–2021–0317–0810, EPA–HQ–OAR–2021–0317–0814, EPA–HQ–OAR–2021–0317–0817, EPA–HQ–OAR–2021–0317–0924, and EPA–HQ–OAR–2021–0317–0955.

[109] See Document ID Nos. EPA–HQ–OAR–2021–0317–0738, EPA–HQ–OAR–2021–0317–0938, and EPA–HQ–OAR–2021–0317–0844.

third party interested in identifying and notifying owners and operators of super-emitter emissions events must be pre-approved by the Agency for the notification to be valid. This approval process would follow submission of a request for approval as a qualified third-party notifier to the EPA that demonstrates the potential notifier's technical expertise in the specific technologies and detection methodologies proposed for the identification of super-emitter emissions events (*i.e.,* remote-sensing aircraft, mobile monitoring platforms, or satellite). This demonstration would include technical expertise in the use of the detection technology and interpretation, or analysis, of the data collected by the technology. The EPA would maintain a public list of approved qualified third-party notifiers so owners and operators can verify approval before being required to act on a notification. These approved notifiers could be any third party, including but not limited to technology vendors, industry, researchers, non-profit organizations, or other parties demonstrating technical expertise as described. The EPA is soliciting comment on this approval criteria, including whether additional criteria would be appropriate.

Once approved, a qualified notifier would be required to submit specific information in the notification. Providing actionable data of known quality to the owner or operator is essential to ensure resources are focused on swiftly eliminating the super-emitter emissions event. Therefore, the EPA is proposing that each notification must contain specific information to help owners and operators verify that the emissions are correctly linked to their site and aid in a focused investigation to swiftly identify the source of emissions. Specific information that would be required in each notification includes: (1) The location of emissions in latitude and longitude coordinates, (2) description of the detection technology and sampling protocols used to identify the emissions, (3) documentation depicting the emissions and the site (*e.g.,* aerial imaging with emissions plume depicted), (4) quantified emissions rate, (5) date(s) and time(s) of detection and confirmation after data analysis that a super-emitter emissions event was present, and (6) a signed certification that the notifier is an EPA-approved entity for providing the notification, and the information was collected and interpreted as described in the notification. The EPA believes this level of specificity is necessary to provide owners and operators with credible information, and address the concerns raised by commenters that owners and operators could experience undue burden investigating emissions from monitoring data that are not collected in a rigorous manner. We are soliciting comment on the specific required elements of the notification, including whether additional requirements should be added to aid in verifying the credibility of this information.

The EPA further proposes that the entity making the report shall provide a complete copy to the EPA and to any delegated state authority (including states implementing a state plan) at an address those agencies shall specify. The EPA would then promptly make such reports available to the public online. Third parties may also make such reports available to the public on other public websites. The EPA would generally not verify or authenticate the information in third party reports prior to posting.

The EPA is seeking comment on whether it should establish a procedure for owners and operators to suggest that EPA reconsider the approval granted to a third-party notifier. One type of procedure the EPA has considered would be based on information provided by the owner or operator that demonstrates they had received more than three notices at the same site and from the same third party for super-emitter emissions events which the owner or operator demonstrates, after opportunity for response by the third party, that the notifications contain meaningful, demonstrable errors, including, for example, that the third party did not use the appropriate methane detection technology, or that the emissions event did not exceed the threshold. Where such demonstrable error is identified, the owner and operator would not be obligated to conduct the root-cause analysis and corrective action discussed later in this section and could, instead, submit a report indicating the error. The EPA would not allow use of this type of mechanism to dispute the accuracy of technologies that have been approved by the EPA. Given the intermittency of super-emitter emissions events, the failure of the operator to find the source of the super-emitter emissions event upon subsequent inspection would not be proof, by itself, of demonstrable error on the part of the third-party notifier. The EPA, in its discretion, may remove that third party from the pre-approved list of third-party notifiers upon demonstration by the owner or operator and/or a finding by the EPA that more than three notifications to that same owner or operator were made in error.

The design of the super-emitter response program ensures that the EPA will make all of the critical policy decisions and fully oversee the program. The proposed framework for the super-emitter response program further includes a robust series of safeguards to ensure that these notifications represent validly collected data and evidence of a super-emitter emissions event. First, the qualified third party permitted to submit notifications must be certified by the EPA as having appropriate experience and expertise. Second, the qualified third party may only use certain remote detection technology approved by the EPA for use in the super-emitter response program. Third, the EPA would establish the threshold defining what emissions events detected by the qualified third parties would trigger any obligation on the part of the owner and operator under the program. Fourth, the EPA has prescribed the specific factual information that must be included in any appropriate notification provided to an owner or operator. And fifth, the EPA has proposed a mechanism for owners and operators to seek a revocation of a notifier's certification from the EPA should they establish that more than one notification contained demonstrable errors. Accordingly, under this framework the qualified third party would essentially only be permitted to engage in certain fact-finding activities and issue fact-based notifications within the limited confines that the EPA has authorized. Such fact-based notifications originating from third parties would not represent the initiation of an enforcement action by the EPA or a delegated authority.

In addition, and as discussed in more detail later in this section, owners and operators would have the opportunity to rebut any information in a notification provided by the qualified third parties in their written report to the EPA, by explaining, where appropriate, that (a) there was a demonstrable error in the third party notification; (b) the emissions event did not occur at a regulated facility; or (c) the emissions event was not the result of malfunctions or abnormal operation that could be mitigated. And, as just discussed, the EPA proposes to retain the authority to revoke a third-party certification upon evidence that the notifier has made repeated, demonstrable errors in notifications provided to owners and operators.

Thus, the EPA believes that the proposed program appropriately limits third party notifiers' discretion and retains oversight by the EPA over all key decision-making elements of the program. In light of these considerations, the EPA also believes that a greater role for the Agency in reviewing third-party notifications would be an unnecessary task and duplicative of the predicate approval processes and subsequent revocation procedure. Indeed, were the EPA to review third-party notifications, such review could potentially be limited to ensuring that the third party is properly EPA-certified, has used an EPA-approved remote monitoring technology, and has found emissions above the super emitter threshold—all of which are elements that the proposed program structure adequately ensures. The EPA believes other facts necessary to rebut the information in a notification regarding a particular emissions event are likely to only be known by the owner and operator and are best presented in their written report to the EPA. Moreover, given the urgency with which the EPA believes such large emissions events should be addressed, any additional role for the EPA in the notification process would unnecessarily delay mitigation of ongoing harms. The EPA solicits comments on these conclusions, and whether there would be a meaningful benefit to a greater role for the EPA in reviewing and/or approving third-party notifications before the obligation of the owner or operator to respond is triggered. And if so, the EPA further solicits comment on what kind of role would be appropriate without meaningfully delaying the mitigation of the large emissions events this program is intended to target.

Addressing a super-emitter emissions event. In the November 2021 proposal, the EPA solicited comment on what specific actions an owner or operator would be required to take when they are notified of the detection of a super-emitter emissions event. Examples of those specific actions were provided for comment, including verifying the location of the emissions, conducting ground investigations to identify the specific emissions source, conducting a root cause analysis, performing corrective action within a specific timeframe to mitigate emissions, and preventing ongoing and future chronic or intermittent events from that source. See 86 FR 63177 (November 15, 2021). One commenter stated that not all sources of super-emitter emissions events would require a root cause analysis with corrective actions because the emissions may not be the result of malfunctions or abnormal operation (*e.g.,* an emergency blowdown of equipment).[110] Other commenters stated that a root cause analysis and immediate corrective actions should be required for any event identified through this program.[111]

The EPA agrees with commenters that swift action must be taken when an owner or operator is notified about the detection of a super-emitter emissions event to correct any malfunction or abnormal operation that is identified as the cause of the event. First, the owner or operator should confirm that the reported emissions event is traceable to a source located on the notified owner or operator's site and investigate to confirm if a super-emitter emissions event is still ongoing. Further, the EPA agrees that a root cause analysis is necessary to identify the causes of the super-emitter emissions event. Therefore, we are proposing to require owners and operators to initiate a root cause analysis to determine the cause of the super-emitter emissions event and to take corrective actions to mitigate the emissions. Examples of a root cause analysis and corrective action could range from a survey using OGI or other technologies combined with repairs of any leaks identified, to visual inspections of thief hatches and closing any found open or unlatched. As explained in more detail later in this section, such corrective actions are tasks that owners and operators already would undertake to maintain normal operations. One commenter[112] noted that the investigation may find the emissions are attributed to something other than a malfunction or abnormal emission; in those cases, the responsive action may only need to include specific documentation of the emissions source, such as maintenance activities, which should be described in the report.

The EPA is proposing to require initiation of the root cause analysis and corrective actions within five calendar days of an owner or operator receiving the notification of the super-emitter emissions event, and completion of corrective actions within 10 days of the notification. Because super-emitter emissions events are such large mass emissions rates (100 kg/hr or greater), it is imperative that mitigation is achieved in a timely manner. One commenter[113] suggested a program where the investigation would start within 14 days of notification, with repairs completed within 30 days of discovery of the event. However, the EPA believes that identification of the emissions source and remedial action in a much shorter timeframe is both warranted and necessary.

Notwithstanding the necessary urgency of mitigating super-emitter emissions events, the EPA does recognize that in some cases, significant efforts may be required to fully complete required mitigation. It is possible that some corrective actions would take longer than the proposed 10 days to complete. Therefore, the EPA is proposing a requirement for owners and operators to develop and submit a corrective action plan that describes the corrective action(s) completed to date, additional measures that they propose to employ to reduce or eliminate the emissions, and a schedule for completion of those measures. This corrective action plan would be due within 30 days of receipt of the notification of the super-emitter emissions event. This timeframe allows for an additional 20 days beyond the repair deadline to draft the corrective action plan and submit it to the Agency or delegated state authority.

Finally, the EPA is proposing to require the submission of a written report within 15 days of completing the root cause and corrective action to the Agency and delegated state authority. In the case of a designated facility covered by a state plan, the EPA solicits comment on whether such written report should be sent to the state in addition to the EPA. The EPA would promptly post online all reports received from the owner-operator in response to a notice of super-emitter event. This written report would include information such as the data included in the notification, the source of the emissions, corrective actions taken to mitigate the emissions, and the compliance status of the affected facilities. To the extent a deviation or potential violation is identified as the root cause of the emissions, the owner or operator would report that information. If the operator finds that emissions above the super-emitter threshold are not occurring, and there is no evidence that they may have occurred as reported, then the method for making that determination and the evidence in support should be included in the required report to the EPA. To the extent an owner or operator determines that the notification contains a demonstrable error (*e.g.,* that the notifier was not a qualified third party, that the third party did not use the appropriate methane detection technology, or that

[110] See Document ID No. EPA–HQ–OAR–2021–0317–1391.

[111] See Document ID Nos. EPA–HQ–OAR–2021–0317–0586, EPA–HQ–OAR–2021–0317–0605, and EPA–HQ–OAR–2021–0317–0832.

[112] See Document ID No. EPA–HQ–OAR–2021–0317–1391.

[113] See Document ID No. EPA–HQ–OAR–2021–0317–0832.

the reported emissions event did not exceed the threshold), the report would need only include a description of the error and an explanation as to why, under these circumstances, a root cause analysis was not conducted. The EPA solicits comment on what other elements should be included in the owner-operator reports to the state and the EPA.

The EPA solicits comment on these proposed deadlines for initiating the analysis and completion of corrective actions. For comments requesting shorter or longer timeframes, we are requesting specific examples that would support any changes to this proposal.

b. Statutory Basis of Super-Emitter Program

There are several ways in which the proposed super-emitter response program described above fits within the EPA's authority under section 111 of the CAA, and two legal frameworks are outlined below.

First, the EPA could treat a super-emitter emissions event as a separate and distinct source of emissions. Under this regulatory framework, sources of super-emitter emissions events from unintended venting would be an affected facility/designated facility, and the super-emitter response program would serve as the standard reflecting the BSER for these facilities.

Specifically, the EPA is proposing a new "super-emitter" affected facility under NSPS OOOOb (and designated facility under EG OOOOc), which the EPA would define as any equipment or control devices, or parts thereof, at a well site, centralized production facility, compressor station, or natural gas processing plant, that causes a super-emitter emissions event (*i.e.,* any emissions detected using remote detection methods with a quantified emission rate of 100 kg/hr of methane or greater). While the other requirements proposed as part of this rulemaking are intended to reduce or eliminate unintentional releases, the super-emitter response program is intended as a backstop to those provisions, to identify any super-emitter emissions events not prevented as a result of other requirements of the proposed rule.

As discussed above, the EPA believes that super-emitter emissions events from unintentional releases tend to occur as a result of equipment malfunctions and/or poor operations; therefore, the BSER for super-emitter emissions events would be to correct the malfunction or operational issues and resume normal operations consistent with the standards or requirements applicable to the source(s) of the super-emitter emissions event in this proposed rule. The November 2021 proposal and this supplemental proposal contain standards and requirements that, if implemented correctly, would prevent or mitigate these super-emitter emissions events. For example, if a root cause analysis identifies a control device as a source of a super-emitter emissions event, then complying with the requirements for that control device in this proposed rule would bring such device back to normal operation. If the source of a super-emitter emissions event is a leaking fugitive emissions component or an open thief hatch, repairing the component or ensuring that the thief hatch is closed in accordance with the fugitive emissions standards in this proposal would resume these components to normal operation. The super-emitter response program would require that, where approved, qualified third parties or state or Federal governments provide actionable data of known quality about a super-emitter event to owners and operators of a super-emitter affected facility, and owners and operators would conduct a root-cause analysis to identify the sources of the super-emitter emissions and take corrective actions to mitigate the problems in order to resume normal operation. Because specific corrective actions required to resume normal operations would depend on the equipment causing the super-emitter emissions event, and because normal operations could differ from site to site, the proposed program would allow owners and operators to determine the appropriate corrective actions so long as the event is mitigated.

The EPA proposes to determine that these requirements are justified as BSER for this proposed super-emitter affected/designated facility for several reasons. First, we expect that, as part of normal operations, owners and operators should already be correcting equipment malfunctions and/or poor operations as such issues arise; therefore, costs associated with maintaining normal operations should already be accounted for in their operational costs. As mentioned above, the most widely known sources of unintended super-emitter emissions events are from equipment or control devices that would be subject to emission limitations (*e.g.,* 95 percent reduction) or associated compliance assurance requirements in the proposed NSPS OOOOb/EG OOOOc. For these sources, where a super-emitter emissions event suggests a violation of one or more of these standards or requirements, owners and operators would already be required to investigate the source of the super-emitter emissions event to ensure that it is complying with all applicable standards and requirements. The proposed super-emitter response program would simply require the owner and operator to take these same steps upon receiving notice of a super-emitter emissions event, provided by a regulatory authority or an EPA approved qualified third party, as determined under the proposed program. As explained in more detail above, the proposed super-emitter response program would include a certification process and other criteria to assure the quality and reliability of third-party data regarding a super-emitter emissions event. Having established the reliability and quality of the third-party data regarding a super-emitter emissions event, it is reasonable to require prompt investigation and remediation of the emissions. Super-emitter emissions events could also be caused by fugitive emissions components that, if persistent, would be detected and repaired during the next fugitive monitoring survey; the super-emitter program would simply make the same repair earlier. There would be no associated monitoring cost for owners and operators, as monitoring under this program would be conducted by EPA-approved qualified third parties. Accordingly, the EPA anticipates that there should be no additional cost associated with this work practice standard for the super-emitter emissions event affected facility. The EPA seeks comment on this issue.

To the extent there are additional costs associated with the investigation or mitigation of these events, the EPA anticipates that the costs would be minor in relation to the benefits of stopping such a huge emissions event, making them obviously cost-effective, as explained below. The EPA proposes that it is reasonable to conclude that these actions would be cost effective in light of the large mass emissions rate (100 kg/hr of methane or greater) that would be reduced and the value of the high volume and value of gas saved by mitigation of the event. The EPA finds in the November 2021 proposal and this supplemental proposal that some proposed standards are cost effective when they result in an expected reduction of about 10 tons of methane at a facility over the course of a year. The super-emitters that can be identified through the super-emitter response program produce that amount of methane in five days or less and the remedies are the same or similar.[114] For example, if the source of a super-emitter emissions event is an open thief hatch on a controlled tank battery, the first corrective action would be to close the thief hatch, which would incur negligible costs. In other words, it is highly unlikely that in general these actions would exceed the $2,185/ton of methane reduced, which is the highest value we have determined to be cost effective for reducing methane in rulemakings addressing methane under section 111 of the CAA. The cost effectiveness for responses to super-emitter emissions events will usually be substantially below this threshold, given that, by definition, super-emitter emissions events emit at least one ton of methane every nine hours, and over 18 tons in a week. For the reasons stated above, the EPA anticipates that requiring immediate corrective actions to resume normal operations to eliminate the super-emitter emission event could be achieved at a reasonable cost for this proposed affected/designated facility. The EPA seeks comment on this conclusion.

The EPA finds that the above regulatory framework of treating super-emitter emissions events from unintended venting as an affected facility that would be subject to the super-emitter response program is a clear, simple, and straight forward approach for addressing such large emission events.

Second, the super-emitter response program can be justified as part of the standards and requirements that apply to individual affected/designated facilities under this rule, a number of which are known to be frequent causes of super-emitter emission events which, as explained earlier, may not necessarily be identified and addressed through more frequent monitoring that we have determined is not cost-effective. As mentioned above, the most widely known sources of unintentional releases resulting in super-emitter emissions events are from controlled tank batteries, flares, natural gas-driven pneumatic controllers, and fugitive emissions, all of which would be either affected facilities or designated facilities under the NSPS OOOOb and EG OOOOc, respectively, or are control devices used on affected facilities/designated facilities for which the proposed rules include specific requirements. The EPA proposes to incorporate the super-emitter program into these standards by considering the super-emitter program as: (1) An additional compliance assurance measure, in the case of sources that are subject to numerical standards of performance and associated control device requirements, and (2) an additional work practice standard, in the case of sources for which the EPA is proposing work practice standards under this rule. However, despite the proposed incorporation, the super-emitter response program is nevertheless severable from the standards of performance and work practice standards that are being separately established for each of the sources addressed in this rule. Each of these other proposed standards in this rule reflects the use of a specific emission reduction or detection technology or measure that the EPA has determined to be BSER for a given emission source after evaluating its performance, cost and other factors associated with its use, as required by CAA section 111(a) (under the definition of a ''standard of performance''). Because whether such technology or measure qualifies as the BSER under CAA section 111(a) does not depend on the presence of the super-emitter response program, the resulting standards of performance and work practice standards proposed in this rulemaking would continue to reflect the use of that technology or measure, and in turn the BSER, even without the super-emitter response program.

Compliance assurance. For super-emitter emissions events from affected facilities/designated facilities subject to numerical standards, the super-emitter response program would serve as an added compliance assurance mechanism, aimed at ensuring compliance with the numerical emissions standards and associated control device or other compliance assurance requirements. Where one of these facilities is determined to be the cause of a super-emitter emissions event, it is reasonable to assume that the emissions source is out of compliance and to require corrective action to bring the facility back into compliance with the applicable standard or requirement.

There are two known sources of unintended venting that could result in super-emitter emissions events that would be subject to numerical performance standards as affected facilities or designated facilities: tank batteries with potential emissions above six tpy of VOC or 20 tpy of methane and natural gas-driven pneumatic controllers. Specifically, for storage vessel affected facilities/designated facilities, the EPA is proposing a numerical standard of performance that would require reducing VOC and methane emissions by 95 percent. Where a control device is used to meet this standard, the EPA is proposing specific compliance assurance measures, such as a requirement that thief hatches and other openings remain closed (''closed cover requirements''). As discussed in section IV.I of this preamble, the EPA is proposing to require quarterly OGI inspections of thief hatches and other openings to ensure the closed cover requirement, and in turn the 95 percent emission reduction standard, are met. If these standards and requirements are rigorously followed, the EPA anticipates that they should prevent super-emitter emissions events from controlled storage tanks. However, these thief hatches are a commonly known source of super-emitter emissions events when they are not closed and properly latched. The proposed super-emitter response program would therefore serve as a backstop—an additional compliance assurance measure for the storage vessels standards—by requiring corrective action where it is determined that a super-emitter emissions event was caused (in whole or in part) by noncompliant storage vessels. Similarly, with respect to natural gas-driven pneumatic controllers, for which the EPA is proposing a zero-emissions standard, the EPA is proposing to require quarterly OGI inspections of self-contained natural gas-driven pneumatic controllers to ensure there are no identifiable emissions from the controller as a compliance assurance measure. The super-emitter response program would serve as an additional compliance assurance measure by requiring immediate corrective action where it is determined that a super-emitter emissions event was caused (in whole or in part) by a natural gas-driven pneumatic controller affected facility.

As mentioned above, flares are also a widely known cause of super-emitter emissions events. To our knowledge, all flares located at well sites, centralized production facilities, compressor stations, or natural gas processing plants are (or would be) used to meet a performance standard in NSPS OOOOb or EG OOOOc. As such, they would be required to meet the design and operation requirements for flares in this proposal, such as operation and monitoring for a continuous pilot. Flares designed and operated according to the proposed requirements for control devices should not cause a super-emitter emissions event. The super-

[114] See Table 11, Summary of Emission Reductions and Cost-Effectiveness: Well Sites with Major Production or Processing Equipment, Quarterly Monitoring.

emitter response program would help assure compliance with these flare requirements (and in turn the relevant performance standards) by requiring owners and operators to take immediate corrective actions to bring that flare into compliance where it is determined that a super-emitter emissions event is caused by a flare. For these sources, where a super-emitter emissions event suggests a violation of one or more of these standards or requirements, owners and operators would already be required to investigate the source of the super-emitter emissions event to ensure that it is complying with all applicable standards and requirements. Since the proposed super-emitter response program would require these same measures, we do not anticipate additional costs associated with the program.

To the extent there are additional costs associated with the investigation or mitigation of these events, the EPA expects that the costs would be minor in relation to the benefits of stopping such a huge emissions event, making them obviously cost-effective. As explained previously in this section, it is reasonable to conclude that these actions would be cost effective in light of the large mass emissions rate (100 kg/hr of methane or greater) that would be reduced and the value of the high volume of gas saved by mitigation of the event.

Work practice standards for detecting and repairing fugitive emissions. As discussed above, super-emitter emissions events may also occur from fugitive emissions components, which are not subject to numerical standards, but rather to a work practice standard that requires periodic monitoring (using OGI, AVO, or an advanced technology) and repair of emissions that are identified from fugitive emissions components. A super-emitter emissions event could occur between the required periodic monitoring and thus not be detected and repaired until the next periodic monitoring event. In addition, if required periodic monitoring is missed, or is not performed well, super-emitter emissions events could be occurring that the periodic monitoring program fails to identify. For affected facilities and designated facilities (*i.e.,* collection of fugitive emissions components) subject to the periodic monitoring and repair requirements, the super-emitter response program would serve as an additional work practice standard that would require corrective action whenever the owner or operator is notified of a super-emitter emissions event by an EPA, a state, or an approved third party under the super-emitter response program, and it is determined that fugitive emissions components are (in whole or in part) the source of the event.

While, as discussed in section IV.A.1, the EPA does not believe it is cost-effective to require operators to conduct periodic OGI monitoring more frequently than the intervals set out in Section IV.A.1, if a super-emitter emissions event is detected by a regulatory authority or approved qualified third party in between monitoring requirements, the EPA proposes that the BSER include responding to that event and addressing the root cause of the super emission.

The more targeted super-emitter response program would thus be a more effective solution for addressing sporadic, large emission events that may occur outside the periodic OGI monitoring. The conclusion that the super-emitter response program is appropriate for addressing these particularly large emissions events does not undermine the EPA's determination about the frequency of periodic monitoring otherwise required under the fugitive emissions work practice standard. While super-emitter emissions events are important to address as a significant source of potential emission reductions, these events do not occur regularly across all well sites and are not predictable. Accordingly, while the periodic monitoring is appropriate to address more routine leak detection and repair, and to help prevent the occurrence of super-emitter emissions events, the super-emitter response program will help ensure that the unpredictable but potentially significant super-emitter emissions events are expeditiously addressed.

Further, the corrective action to mitigate a super-emitter emissions event from this source has the potential to result in significant emissions reductions earlier than would have been achieved by the periodic monitoring requirements. The EPA therefore believes that the super-emitter response program is a reasonable addition as part of the BSER for fugitive components because the program would only target particularly large emission events (measuring over 100 kg/hr) from these affected or designated facilities and would not require any action for smaller emissions events that would be addressed by the periodic monitoring.

We have considered the costs of adding the super-emitter response program as an additional work practice standard to the periodic monitoring and repair requirements for addressing fugitive emissions and concluded that the cost is reasonable. First, owners and operators do not bear the cost of monitoring and detecting super-emitter emissions events, which would be conducted by EPA-approved qualified third parties. Instead, as discussed in more detail below, the first step of the program would be for owners and operators to investigate and identify the source(s) of a super-emitter emissions event upon receiving reliable information. Since owners and operators would already have to perform this task for purposes of the compliance assurance measure for other affected facilities and associated control devices under the super-emitter response program, described above, there would be little additional cost in including this same root-cause analysis as part of the fugitive emissions work practice standards. Second, to the extent a root-cause analysis reveals that the super-emitter emissions event is caused by a fugitive emissions component, there may be no additional cost associated with their repair, since these fugitive emissions might be detected and repaired during the next scheduled periodic monitoring; the super-emitter response program would simply require such repair to occur sooner. In other words, for super-emitter emissions events identified as resulting from fugitive emissions components between scheduled monitoring surveys, the proposed super-emitter response program would provide an opportunity for repairs sooner than the next scheduled survey, thus resulting in fewer emissions overall from the event.

Moreover, even if there are costs associated with the investigation and mitigation, the threshold for identifying a super-emitter emissions event is so high that it ensures that the emissions reductions achieved by the mitigation are cost-effective. In other words, it is reasonable to conclude that these actions would be cost-effective in light of the large mass rate of emissions (100 kg/hr of methane or greater) that would be reduced, and the high volume of gas saved. It is highly unlikely that these actions would exceed the $2,185/ton of methane reduced, which is the highest value we have determined to be cost effective for reducing methane from sources within this source category.

In summary, the EPA finds the data demonstrate that the super-emitter response program is cost-effective, even though the EPA recognizes that the total emissions reductions that will result from the program are difficult to quantify. By definition, a super-emitter emissions event emits more than 100 kg of methane/hour, which means that an on-going super-emitter emissions event that lasts an extended period may emit more than 2.5 tons of methane in a day, and potentially almost 80 tons if it continued undetected for a month. Applying the same social cost of methane values used to develop the estimates in Table 5 above, such an event could generate over $100,000 in avoidable climate damages.[115] The proposed fugitive emissions monitoring and repair requirements for facilities with major production and processing equipment, discussed in section IV.A, are cost-effective when they are projected to reduce 10.85 tpy of methane. A super-emitter emissions event may emit almost twice that, or in some cases substantially more, in a single week. In addition, the cost of most of the repairs that would be necessary to respond to a super-emitter emissions event may be achieved at very low additional cost because the need for repair would be discovered at the next required inspection, indicating that most repairs in response to super-emitter emissions events may be simply moving the repairs earlier in time. Furthermore, halting super-emitter emissions events recovers natural gas for sale that would otherwise be emitted to the atmosphere, so it is possible that for many super-emitter emissions events identified, the revenues from recovered natural gas may offset a significant portion of the costs of repair incurred by the owner or operator. For all these reasons, the EPA finds the super-emitter response program cost-effective. Because the costs of this program incurred by owners and operators, the length of time over which these events occur, and the emissions reductions that may be achieved have uncertainties associated with them, the EPA solicits comments on the various factors related to the cost-effectiveness of the super-emitter response program, including any information further detailing the costs and emissions reductions of this program. Specifically, the EPA solicits comments on any relevant data, appropriate methodologies, or reliable estimates to help quantify the costs, emissions reductions, benefits, and potential distributional effects of this program (including, for example, benefits for communities with EJ concerns). We also take comment on how to improve the accuracy of our estimates of baseline emissions levels, emissions reduction opportunities, and the frequency and intensity of super-emitter events, and how to incorporate any recent, reliable estimates of methane emissions.

c. Additional Solicitations for Comment

While the EPA is proposing a general framework for the super-emitter response program, there are several additional aspects of the program for which we are soliciting additional information and comment. These solicitations are described in the following paragraphs.

First, the EPA is soliciting comment on the mechanism for identifying the owners and operators to receive the super-emitter emissions event notifications. Entities approved to make such notifications need a way to identify to whom they should be sent and how to assure they are received. The EPA specifically seeks comment on what mechanisms exist to make such identifications now, the reliability, accuracy, and timeliness of those mechanisms, and the difficulty or cost of accessing those mechanisms.

The EPA is also soliciting comment on the amount of time allowed for notifications following detection of a super-emitter emissions event. Clearly, timely notification of the event is essential to maximize the emission reduction potential from the event, but it is the EPA's understanding that each technology or remote measurement method experiences a lag between when a survey is conducted and when the data has been analyzed to demonstrate emissions were present. The EPA is soliciting comment on what deadline for notifications following detection survey is most advantageous and feasible given current data analysis requirements for remote measurement technologies and methods. Further, time will be required to properly identify the relevant owner or operator of the site. One factor is that ownership of sites can change frequently, or specific contacts may move into other roles or leave the company. Therefore, the EPA is soliciting comment on the amount of additional time that should be factored into the notification process to account for this identification step.

D. Pneumatic Controllers

Pneumatic controllers are devices used to regulate a variety of physical parameters, or process variables, often using air or gas pressure to control the operation of mechanical devices, such as valves. The valves, in turn, control process conditions such as levels, temperatures and pressures. When a pneumatic controller identifies the need to alter a process condition, it will open or close a control valve. In many situations across all segments of the Oil and Natural Gas Industry, pneumatic controllers make use of the available high-pressure natural gas to operate or control the valve. In these ''natural gas-driven'' pneumatic controllers, natural gas may be released with every valve movement (intermittent) and/or continuously from the valve control. Detailed information on pneumatic controllers, including their functions, operations, and emissions, is provided in the preamble for the November 2021 proposal (86 FR 63202–63203; November 15, 2021).

1. NSPS OOOOb

a. November 2021 Proposal

In the November 2021 proposal, a pneumatic controller affected facility was defined as each single natural gas-driven pneumatic controller, whether the controller was a continuous bleed controller or an intermittent vent controller. This affected facility definition would have applied at sites in all segments of the oil and natural gas source category. We proposed the requirement that all controllers (continuous bleed and intermittent vent) have a VOC and methane emission rate of zero. The proposed rule did not specify how this emission rate of zero was to be achieved, but a variety of viable options were discussed. These options included the use of pneumatic controllers that are not driven by natural gas such as instrument air-driven pneumatic controllers and electric controllers, as well as natural gas-driven controllers that are designed so that there are no emissions, such as self-contained pneumatic controllers. Because we proposed to define an affected facility as each pneumatic controller that is driven by natural gas and that emits to the atmosphere, pneumatic controllers not driven by natural gas would not have been affected facilities. Controllers that are driven by natural gas but that do not emit to the atmosphere would not have been affected facilities either, according to the November 2021 proposed definition.

The November 2021 proposed rule included an exemption from this zero-emission standard for pneumatic controllers at sites in Alaska that do not have access to electrical power. For these sites, the proposed rule would have required the use of low-bleed, continuous bleed controllers. It would also have required that intermittent vent controllers not vent during idle periods and that periodic inspections be performed on these controllers to ensure that such venting does not occur.

[115] This damage estimate assumes a social cost of methane estimate of at least $1,400 per metric ton of methane, which is less than the interim estimate that EPA uses in the RIA for a 3% discount rate for the first year that the proposed NSPS OOOOb is assumed to go into effect (2023).

b. Changes to Proposal and Rationale

The proposed NSPS OOOOb requirements in this supplemental proposal differ from the November 2021 proposal in several ways, starting with the affected facility definition. As noted above, the pneumatic controller affected facility definition proposed in November 2021 was each individual natural gas-driven pneumatic controller. In this supplemental proposal, a pneumatic controller affected facility is defined as the collection of all the natural gas-driven pneumatic controllers at a site.

Another change from the November 2021 proposal is that two specific types of natural gas-driven controllers that were proposed to be excluded from the affected facility definition are now proposed to be included. These are: (1) Controllers where the emissions are collected and routed to a gas-gathering flow line or collection system to a sales line, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve (*i.e.,* generally characterized as ''routing to a process''); and (2) self-contained natural gas pneumatic controllers.

There is no change to the fundamental proposed standard for pneumatic controllers, which is that all pneumatic controllers would be required to have a methane and VOC emission rate of zero. The proposed standard does include requirements for the two specific types of natural gas-driven controllers identified above. These controllers do not emit methane or VOC from routine operations. However, since they are powered by natural gas, the potential for emissions exists if they are not maintained and operated properly. For instance, a self-contained controller could malfunction or develop leaks, or a CVS that is routing the controller emissions to a process could develop leaks. Therefore, the proposed rule includes requirements to avoid such situations so that the controllers have zero direct emissions. Since routing to a process includes the option of using the natural gas captured for use as a fuel source, emissions would occur downstream at the engine, generator, or process heater resulting from the combustion of the natural gas from the controllers. However, these emissions are replacing those that would have resulted from the combustion of fuel gas, meaning that the net result is still zero direct emissions.

While the BSER conclusion did not change from the November 2021 analysis, the EPA did update the analysis based on information received in the public comments, including an analysis of potential alternative standards for small sites with few pneumatic controllers.

Details on the proposed pneumatic controller requirements in this supplemental proposal are provided below in section IV.D.1.c. The following sections provide the rationale for the changes discussed above, a discussion of other related issues raised by commenters, and the updated BSER analysis.

i. Affected Facility, Modification, and Reconstruction

As noted above, the pneumatic controller affected facility definition changed from being based on a single continuous bleed or intermittent vent controller in the November 2021 proposal to the collection of natural gas-driven continuous bleed and intermittent vent controllers at a site in this supplemental proposal.[116] The EPA is proposing this change based on the consistent recommendation of numerous commenters, particularly commenters from the oil and natural gas industry. Several comments on the November 2021 proposal noted the disconnect between the pneumatic controller affected facility definition (*i.e.,* an individual controller) and the cost analysis, which was based on the replacement of all pneumatic controllers with zero-emitting devices at a site.[117] One commenter pointed out the complexities of tracking and managing the universe of pneumatic controllers at a site when some are affected facilities and others are not, and recommended that the EPA propose a simpler and more robust system.[118] Another commenter indicated that defining the affected facility on a site-wide basis aligns with how emissions from pneumatic controllers will likely be handled by owners and operators of oil and natural gas facilities. This commenter opined that defining the pneumatic controller affected facility on a single controller basis, as opposed to as the collection of all controllers at a site, would be unnecessarily burdensome.[119] A separate commenter discusses the fact that converting a single pneumatic controller to a zero-emitting device typically requires a conversion of all controllers at the facility to zero-emitting devices.[120]

We agree with the commenters that defining the pneumatic controller affected facility as the collection of all controllers at a site is the most practical approach. Significantly, most of the zero-emissions measures for pneumatic controllers are site-wide solutions. For instance, a compressed air system installed at a site would be used to power all of the pneumatic controllers at the site, rather than a separate system for each controller. Similarly, a solution based on solar energy would likely utilize a single array of solar panels to provide power to all the controllers at the site. In fact, as pointed out by the commenters, the analysis for the November 2021 proposed rule was conducted on a ''model plant'' site-wide basis. As noted above, the comments that the EPA received on the pneumatic controller affected facility definition in the November 2021 proposal all advocated for a change in the definition from a single controller to the collection of all onsite pneumatic controllers. However, the EPA did not specifically solicit comment on the particular question of how to define the affected facility in November. Now that the EPA is proposing in this supplemental proposal to define the affected facility as the collection of natural gas-driven continuous bleed and intermittent vent controllers at a site, the EPA solicits comment on the proposed changed definition.

Under the previous approach of treating each controller on an individual basis, the installation or replacement of a pneumatic controller would have resulted in that singular controller being a new source and an affected facility subject to NSPS OOOOb. Under this supplemental proposal approach to treat the collection of all controllers at a site as the affected facility, clear descriptions of modification and reconstruction are needed in order to indicate when an existing collection of controllers would become subject to NSPS OOOOb. In 40 CFR 60.14(a), a ''modification'' is defined as ''any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant.'' To clarify what constitutes a modification for the

[116] The EPA notes that there are other sources of emissions in this supplemental proposed rule that the EPA proposes to regulate as a collection of emissions sources, rather than as individual emission units. Namely, the EPA proposes to define tank batteries as the group of all storage vessels that are manifolded together for liquid transfer and proposes to define fugitive emissions components as the collection of fugitive emissions components at all well sites.

[117] See Document ID Nos. EPA–HQ–OAR–2021–0317–0599, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0831, and EPA–HQ–OAR–2021–0317–0777.

[118] See Document ID No. EPA–HQ–OAR–2021–0317–0742.

[119] See Document ID No. EPA–HQ–OAR–2021–0317–0817.

[120] See Document ID Nos. EPA–HQ–OAR–2021–0317–0808.

collection of all controllers at a site, the supplemental proposed rule specifies that if one or more pneumatic controllers is added to the site, such addition constitutes a modification and the collection of pneumatic controllers at the site becomes a pneumatic controller affected facility. This is because the addition of a controller represents a physical change to the site and would result in an increase in emissions from the collection of controllers. Based on information provided by industry commenters, the EPA believes that owners and operators will implement zero-emissions controllers across a site when a modification occurs because converting a single pneumatic controller to a zero-emitting device typically requires converting all controllers at the facility to zero-emitting devices. The EPA solicits comment on the ways in which a modification to a pneumatic controller affected facility would occur in light of the affected facility definition proposed herein, which includes the collection of all natural gas-driven continuous bleed and intermittent vent controllers at a site.

In 40 CFR 60.15(b), ''reconstruction'' is defined as the replacement of components of an existing facility ''to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility,'' and ''it is technologically and economically feasible to meet the applicable standards.'' The proposed pneumatic controller affected facility definition for this supplemental proposal is the collection of all natural gas driven controllers at a site; therefore, the cost that would be required to construct a ''comparable entirely new facility'' would be the cost of replacing all existing controllers with new controllers. Because individual controllers are likely to have comparable replacement costs, it is reasonable to assume that there would be a one-to-one correlation between the percentage of controllers being replaced at a site and the percentage of the fixed capital cost that would be required to construct a comparable entirely new facility. Accordingly, we are proposing to include a second, simplified method of determining whether a controller replacement project constitutes reconstruction under 40 CFR 60.15(b)(1) whereby reconstruction may be considered to occur whenever greater than 50 percent of the number of existing onsite controllers are replaced.[121] The EPA believes that allowing owners or operators to determine reconstruction by counting the number of controllers replaced is a more straightforward option than requiring owners and operators to provide cost estimate information. By providing this option, the EPA intends to reduce the administrative burden on owners and operators, as well as on the implementing agency reviewing the information. Owners and operators would be able to choose whether to use the cost-based criterion or the proposed number-of-controllers criterion. No matter which option an owner or operator chooses to use, the remaining provisions of 40 CFR 60.15 apply—namely, 40 CFR 60.15(a), the technological and economical provision of 40 CFR 60.15(b)(2), and the requirements for notification to the Administrator and a determination by the Administrator in 40 CFR 60.15(d), (e) and (f). The EPA is proposing that the standard in 40 CFR 60.15(b)(1) specifying that the ''fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility'' can be met through a showing that more than 50 percent of the number of existing onsite controllers are replaced. Therefore, upon such a showing, an owner or operator may demonstrate compliance with the remaining provisions of 40 CFR 60.15 that reference the ''fixed capital cost'' criterion. The EPA solicits comment on its proposal to add an option for owners or operators to use in determining whether reconstruction occurs by showing the number of components replaced. The EPA reiterates that this proposed option would supplement the existing option of determining replacements by fixed capital cost, as set forth in 40 CFR 60.15.

A second factor for consideration in the reconstruction of an existing pneumatic controller affected facility is during what time period the number of controllers replaced or the fixed capital cost of the new components should be aggregated. Consider the following scenario: an owner first seeks to replace 30 percent of the pneumatic controllers of an existing facility and then, shortly after commencing or completing those replacements, the owner seeks to replace an additional 30 percent. The owner would have replaced 60 percent of its controllers in total, and presumably, the fixed capital cost of those two replacement programs would be approximately 60 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. It is unclear under the language of 40 CFR 60.15(d) whether this owner should be deemed to have proposed two distinct replacement programs or instead a single replacement program. The EPA believes that such a stepwise controller replacement program should not be used by facilities undergoing numerous replacement programs close in time to avoid compliance with the NSPS. Failure to regulate these sources would undermine Congress' intent that air quality be enhanced over the long term with the turnover of polluting equipment, and with the intent of the EPA's reconstruction provisions, which are triggered where an existing facility replaces its components ''to such an extent that it is technologically and economically feasible for the reconstructed facility to comply with the applicable standard of performance.''[122] Where a number of controllers are replaced relatively close in time such that the aggregate costs or number of controllers is greater than 50 percent, the EPA proposes to conclude that it is reasonable to treat those replacements as part of a continuous program of controller replacement for purpose of determining reconstruction.

In order to clarify how the regulatory language in 40 CFR 60.15 would apply to the replacement of pneumatic controllers, we are proposing that where an owner or operator applies the definition of reconstruction in § 60.15(b)(1), reconstruction occurs when the fixed capital cost of the new pneumatic controllers exceeds 50 percent of the fixed capital cost that would be required to replace all the pneumatic controllers at the site. The ''fixed capital cost of the new pneumatic controllers'' includes the fixed capital cost of all pneumatic controllers which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year rolling period.[123]

[121] Adding this method of determining ''reconstruction'' for pneumatic controllers is in accordance with 40 CFR 60.15(g), which states that ''[i]ndividual subparts of this part [''Reconstruction''] may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.''

[122] *See* Modification, Notification, and Reconstruction, 40 FR 58,417 (December 16, 1975) (also stating that ''the purpose of the reconstruction provision is to recognize that replacement of many of the components of a facility can be substantially equivalent to totally replacing it at the end of its useful life with a newly constructed affected facility.'').

[123] As noted above, incorporating a set period of time within which numerous component replacements amount to ''reconstruction'' is in accordance with 40 CFR 60.15(g), which provides that ''[i]ndividual subparts of this part

Continued

Thus, the EPA will count toward the greater than 50 percent reconstruction threshold all controllers replaced pursuant to all continuous programs of controller replacement which commence within any 2-year rolling period following proposal of these standards. If the owner or operator applies the definition of reconstruction based on the percentage of pneumatic controllers replaced, reconstruction occurs when greater than 50 percent of the pneumatic controllers at a site are replaced. The percentage includes all pneumatic controllers which are or will be replaced pursuant to all continuous programs of pneumatic controller replacement which are commenced within any 2-year rolling period.

In the Administrator's judgment, the 2-year rolling period provides a reasonable method of determining whether an owner of an oil and natural gas site with pneumatic controllers is actually proposing extensive controller replacement, within the EPA's original intent in promulgating 40 CFR 60.15. The EPA solicits comment on this proposed 2-year rolling aggregation period for all continuous programs of pneumatic controller and pneumatic pump replacement (see section IV.E.b.i. for a discussion of proposing the same approach for determining reconstruction for pneumatic pumps). The EPA is particularly interested in comments regarding whether this approach will make it easier for owners and operators to determine reconstruction at their sites, whether using a set time frame is reasonable and feasible to put into practice, whether two years is an appropriate timeframe, and whether a rolling basis for the two-year time frame is a reasonable calculation (for example, see Scenario 5 below). The EPA is also interested in understanding how frequently controllers and pumps are typically replaced.

[''Reconstruction''] may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.'' In addition, the EPA notes that numerous NSPS and EG regulatory provisions incorporate a 2-year time period into the definition of reconstruction. *See, e.g.,* Standards of Performance for New Stationary Sources; Bulk Gasoline Terminals, 48 FR 37582–83 (August 18, 1983) (explaining need for a fixed period within which to determine reconstruction when component replacement occurs over time and determining that two years is reasonable); 40 CFR 60.506(b) (codifying reconstruction definition to include such a time period for bulk gasoline terminals (40 CFR part 60, subpart XX)). *See also* 40 CFR 60.383(b) (metallic mineral processing plants (subpart LL)); 40 CFR 60.100(f), 60.100a(d) (petroleum refineries (40 CFR part 60, subparts J and Ja)); 40 CFR 60.706(a) (volatile organic compound emissions from synthetic organic chemical manufacturing industry reactor processes (40 CFR part 60, subpart RRR)).

The following are example scenarios of the application of these proposed requirements for a site with 15 natural gas-driven pneumatic controllers. Scenario 1: One of the controllers is to be replaced (at any given time). The collection of controllers at the site would not become a pneumatic controller affected facility because the emissions from the collection of controllers would not be increased (so such action does not constitute a modification). Also, such action would not constitute reconstruction because the fixed capital cost of the replacement of this single controller would not equal 50 percent or greater of the fixed capital cost that would be required to replace all the controllers in the affected facility. Scenario 2: Eight of the controllers are to be replaced at the same time. This would represent reconstruction (because more than 50 percent of the total are being replaced which means that the fixed capital cost of the replacement would exceed 50 percent of the fixed capital cost that would be required to replace all the controllers in the affected facility), so the 15 controllers (*i.e.,* the ''collection'' of controllers at the site) would become a pneumatic controller affected facility. This affected facility would then be subject to the zero-emissions standard, meaning that all controllers at the site, including the eight new controllers and the seven existing controllers, must comply with a methane and VOC emission rate of zero. Scenario 3—six of the pneumatic controllers are replaced in January and seven more controllers are replaced the following April (15 months later). This would represent reconstruction because more than 50 percent of the total number of controllers are being replaced over a 2-year period, so the 15 controllers (*i.e.,* the ''collection'' of controllers at the site) would become a pneumatic controller affected facility at the time the seven controllers were replaced in April. This affected facility would then be subject to the zero-emissions standard, meaning that all controllers at the site must comply with a methane and VOC emission rate of zero. Scenario 4: An additional pneumatic controller is added at any given time. This would represent a modification since it would constitute a physical change and would result in an increase in emissions. The 16 controllers would represent a pneumatic controller affected facility and all would need to comply with a methane and VOC emission rate of zero. Scenario 5: replacement of four of the pneumatic controllers is commenced in January in year 1; replacement of two more controllers is commenced the following April in year 2 (15 months later); replacement of two more is commenced the following March in year 3 (26 months after the initiating replacement in January); and replacement of four more is commenced that August of year 3 (31 months after initiating replacement in January). Only six controllers of the 15 controllers were replaced in the discrete two-year time period that began in January of year 1, and therefore would not meet the proposed reconstruction definition. However, when considered on a rolling 2-year basis, eight of the 15 controllers were replaced over years 2 and 3, which would meet the proposed reconstruction definition. EPA specifically solicits comment on whether the two-year time frame should be implemented on a rolling basis or as a discrete time period.

The EPA also solicits comment on whether it would be appropriate to apply either of the two elements of reconstruction that the EPA is proposing for pneumatic controllers (and pneumatic pumps, as described in section IV.E.) to any other affected facility in NSPS OOOOb and EG OOOOc. Specifically, the EPA is interested in comments regarding whether any other source category would benefit from either: 1) adding an option to determine reconstruction based on the number of components replaced (in addition to the existing option of determining replacements by fixed capital cost, as set forth in 40 CFR 60.15), and/or 2) setting a specific time period within which replaced components will be aggregated toward the greater than 50 percent replacement threshold (assessed either by number or cost), *e.g.,* any two-year period beginning when a continuous program of component replacement commences.

Commenters stated that the EPA should allow like-kind replacement of existing individual controllers without causing the controller to become an affected facility under NSPS OOOOb.[124] The commenters indicated that if the EPA were to not allow this, operators who are voluntarily replacing high-bleed natural gas-driven controllers with low-bleed controllers would likely stop doing so. The EPA's proposed change to a site-wide pneumatic controller affected facility definition would allow the replacement of existing high-bleed controllers with low-bleed controllers without becoming an affected facility, provided that 50

[124] See Document ID Nos. EPA–HQ–OAR–2021–0317–0817 and EPA–HQ–OAR–2021–0317–0831.

percent or less of the controllers are replaced at the same time.

Commenters also encouraged the EPA to provide an exemption for ''temporary sources.'' One commenter provided the example where an operation may require use of temporary or portable equipment for a short period of time (*i.e.,* less than 180 days) where it may not be possible to connect to the grid or route to an onsite control device.[125] Another commenter indicated that non-emitting [126] requirements are not justified for short term controller usage related to a non-stationary source, and exemption of controllers on temporary equipment is consistent with state regulations proposed in New Mexico and finalized in Colorado. The commenter indicated that the EPA should also make it clear that the requirements for pneumatic controllers are not applicable during drilling or completion.[127]

The EPA acknowledges that the focus of the BSER analysis has been on stationary sources and pneumatic controllers that are part of the routine operation of oil and natural gas facilities. Although some type of alternative approach may be warranted for pneumatic controllers associated with temporary operations, we lack sufficient information to include an exemption, or perhaps alternative standards, for pneumatic controllers associated with temporary equipment. Therefore, the EPA is requesting more information on these situations. The EPA would like specific examples of when temporary equipment is utilized, the function of the controllers during this time, how they are powered, and the typical duration of their usage. The EPA also requests information explaining in detail why the zero-emission solutions that are used for the permanent equipment at the site cannot be also utilized for this temporary equipment.

Another change to the affected facility definition in this supplemental proposal is that natural gas-driven controllers from which all emissions are collected and routed to a process, as well as self-contained natural gas-driven pneumatic controllers, are not excluded from the pneumatic controller affected facility definition. The EPA is proposing to include these types of natural gas driven controllers because they are driven by natural gas. While the EPA understands that these controllers have zero routine emissions from the operation of the device and are therefore compliant with the proposed standard when they are properly operated and maintained, they do have the potential to emit methane and VOC if they are not operated and maintained properly. Therefore, we are proposing that natural gas-driven controllers from which all emissions are collected and routed to a process, as well as self-contained natural gas-driven pneumatic controllers (which release gas into the downstream piping and not to the atmosphere), are part of a pneumatic controller affected facility, and therefore subject to the zero methane and VOC emissions standards. Specifically, the proposed rule would require that owners and operators ensure proper maintenance and operation of the controllers. For natural gas-driven controllers from which all emissions are collected and routed to a process, the CVS collecting and routing the emissions to the process must comply with the CVS no identifiable emissions requirements in proposed 40 CFR 60.5411b, paragraphs (a) and (c). Self-contained controllers would be required to be designed and operated with no identifiable emissions, as demonstrated by initial and quarterly inspections using optical gas imaging and any necessary corrective actions.

NSPS OOOOa exempts controllers from the standards for functional needs, ''including but not limited to response time, safety, and positive actuation.'' 40 CFR 60.6390a(a). The November 2021 proposed rule did not include these functional needs exemptions, except for locations in Alaska that did not have access to electrical power. The NSPS OOOOa exemptions were based on the use of a low-bleed natural gas driven pneumatic controller. Because the November 2021 proposed standard would not have allowed the use of natural-gas driven controllers, the EPA did not believe that this exemption was needed.

Several commenters requested that the NSPS OOOOa functional needs exemptions be included in NSPS OOOOb in their entirety, while other commenters indicated that they should only be allowed in very limited instances and only when justification is provided in an annual report. Commenters consistently raised the need to utilize natural gas-driven pneumatic controllers associated with emergency shutdown devices (ESDs). One commenter explained that an ESD is designed to minimize consequences of emergency situations and will only emit in certain isolated circumstances, such as if a well must be shut in. A large change in pressure is required to actuate an ESD, which may not be deliverable in a sufficient time by a compressed air or electric controller. Furthermore, if power is lost, these devices must still be able to function. It is rare that ESDs are activated, and their emissions impact is minimal, but their functional need is necessary and critical to safe operations. The commenter noted that both the current version of the proposed rule in New Mexico and finalized regulations in Colorado offer similar exemptions for ESDs.[128]

The EPA still believes that the overall functional needs exemption is not necessary, as the limitations inherent in low-bleed natural gas-driven controllers are not present in many of the zero emissions options, particularly compressed air. The EPA also notes that any natural gas-driven controller is allowed, whether low or high-bleed, if the emissions are collected and routed to process in a manner that achieves zero methane emissions.

The EPA recognizes the important function of natural gas-driven controllers for ESDs. Rather than including such devices in the affected facility, the EPA is proposing to specifically exclude them from the affected facility definition.

Relatedly, one commenter requested that the EPA allow companies the option to continue to use, or install, a dual natural gas system as a backup for key controller functions. Such a natural gas backup system would be used in the case of electrically actuated controller failure, loss of power, or other contingencies.[129] Another commenter added that if the zero-emissions system (*i.e.,* instrument air) goes down, there is no provision within the proposed rule

[125] See Document ID No. EPA–HQ–OAR–2021–0317–0831.

[126] The terms ''zero emissions'' and ''non-emitting'' are used to describe pneumatic controllers. In Colorado, 5 Code of Colorado Regulations (CCR) Regulation 7, Part D, Section III, defines a ''non-emitting'' controller as ''a device that monitors a process parameter such as liquid level, pressure or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to: no-bleed pneumatic controllers, electric controllers, mechanical controllers and routed pneumatic controllers.'' A routed pneumatic controller is defined as ''a pneumatic controller that releases natural gas to a process, sales line or to a combustion device instead of directly to the atmosphere.'' The EPA is proposing that pneumatic controllers must be ''zero emission'' controllers. The difference in non-emitting, as defined by Colorado and as used by the commenter, and zero emissions, as proposed in this action, is that pneumatic controllers for which emissions are captured and routed to a combustion device are not considered to be ''zero emission'' controllers. Therefore, routing to a combustion device is not an option for compliance with the proposed NSPS OOOOb.

[127] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

[128] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

[129] See Document ID No. EPA–HQ–OAR–2021–0317–0817.

to allow for the temporary use of natural gas. The commenter urged the EPA to evaluate the reliability and availability of such systems that would be deployed at such breadth.[130] The EPA is interested in understanding these backup systems more fully. In particular, the EPA is requesting information on these systems regarding how frequently and for how long these systems are used or would be expected to be used. The EPA is concerned that allowing these backup systems would result in a potential loophole that would enable owners or operators to continue to use natural gas-driven controllers in routine situations. Therefore, the EPA is interested in how the use of these systems could be narrowly defined and how a clear distinction could be drawn between the allowed use of these backup systems and violations of the zero emissions standard.

ii. BSER Analysis

Based on comments received on the November 2021 BSER analysis and updated information provided, the EPA revised the BSER analyses for this supplemental proposal for pneumatic controllers for the production and transmission and storage segments of the industry. The following paragraphs describe the updated information, the changes to the BSER analyses, and the updated results. The analysis for natural gas processing plants, which can be found in the TSD for the November 2021 proposal, was not updated.

Several commenters objected to the emission factors that were used for the analysis. One commenter stated that the emission factors used in the GHGRP petroleum and natural gas source category (40 CFR part 98, subpart W, also referred to as ''GHGRP subpart W'') for pneumatic controllers were developed in the 1990's and that they may no longer be applicable considering technological improvements.[131] Another commenter indicated that the factors used underestimated emissions and that recent research indicates that actual average emissions from pneumatic controllers may be higher than estimated.[132]

The emissions factors used for the November 2021 BSER analysis for the production segment were from a recent study conducted by the American Petroleum Institute (API).[133] The factors for the transmission and storage segment were from Table W–3B of GHGRP subpart W (2021). Since the November 2021 proposal, the EPA has conducted a comprehensive review of available information related to emissions from natural gas-driven pneumatic controllers and has proposed to update the emission factors in GHGRP subpart W to reflect this research (87 FR 36920; June 21, 2022). The EPA concluded that these results are the most appropriate for use in this BSER analysis. The information evaluated for the June 2022 proposed revisions to GHGRP subpart W included the API study. Table 22 provides the emission factors used for the November 2021 analysis and those used for the updated analysis in this supplemental proposal.

TABLE 22—NATURAL GAS-DRIVEN PNEUMATIC CONTROLLER EMISSION FACTORS FOR THE PRODUCTION AND TRANSMISSION AND STORAGE SEGMENTS

Segment/type of controller	Emissions (scf whole gas/hr)	
	2022 Updated analysis	November 2021 analysis
Production:		
Low bleed	6.8	2.6
High bleed	21.2	16.4
Intermittent vent	8.8	9.2
Transmission and Storage:		
Low bleed	6.8	1.37
High bleed	32.4	18.2
Intermittent vent	2.3	2.35

As can be seen in Table 22, the emissions factors for low-bleed and high-bleed increased from those used for the November 2021 analysis, while the intermittent vent factors decreased slightly.

One commenter indicated that while they appreciated that the EPA utilized emission factors from the API's Field Measurement Study, they believed that the use of the average intermittent pneumatic device vent rate was incorrect in this application.[134] They stated that under this proposal, any intermittent device would be monitored routinely and repaired or replaced if malfunctioning, so the more appropriate emission factor is 0.28 scf whole gas/controller-hour, not the average emission factor of 9.2 scf whole gas/controller-hour that the EPA used in the November 2021 proposal. The commenter noted that the average emission factor should only be used for controllers that are not routinely monitored as part of a proactive monitoring and repair program or where the monitoring status is unknown. The commenter stated that the normal operation emission factor should be applied to controllers that are found to be operating normally as part of a proactive monitoring and repair program and contended that this approach achieves a nearly similar level of emission reduction for much less investment by operators.

The EPA agrees with the commenter that the lower emission factor is appropriate to represent the emissions level for intermittent vent controllers that are routinely monitored as part of a proactive monitoring and repair program. While the EPA recognizes that some companies have voluntarily implemented such programs, we do not have information to suggest that the majority of the intermittent vent controllers in operation are part of such a program. The average emission factor that the EPA used considers those low-emitting properly operating controllers, as well as those that are not operating

[130] See Document ID No. EPA–HQ–OAR–2021–0317–0599.

[131] See Document ID No. EPA–HQ–OAR–2021–0317–0749.

[132] See Document ID No. EPA–HQ–OAR–2021–0317–0918.

[133] ''API Field Measurement Study: Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas.'' November 7, 2019—Pittsburg PA. Paul Tupper.

[134] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

properly and that are venting during idle. The EPA finds that this average factor is the correct factor to represent the ''uncontrolled'' emissions from the universe of intermittent vent controllers.

One commenter noted that all three sizes of model plants (small, medium, large) contained one high-bleed natural gas-driven controller. The commenter indicated that some state regulations do not allow for the use of high-bleed controllers and concluded that the EPA's baseline emissions analysis was likely skewed high.[135]

The EPA agrees with this commenter. In addition to state regulations that do not allow the use of high-bleed controllers, in the absence of NSPS OOOOb, NSPS OOOOa would not allow the installation of high-bleed controllers at new sites. Therefore, in the updated analysis for new sources, the EPA did not include any high-bleed controllers in any of the model plants. Table 23 provides a summary of the pneumatic controller model plants and emissions. The emissions shown consider the changes in the emission factors provided above in Table 22.

TABLE 23—SUMMARY OF PNEUMATIC CONTROLLER MODEL PLANTS FOR NEW SOURCES

Segment/model plant	November 2021 analysis					2022 updated analysis				
	Number of controllers			Emissions (tpy)		Number of controllers			Emissions (tpy)	
	HB[a]	LB[a]	INT[a]	CH_4	VOC	HB[a]	LB[a]	INT[a]	CH_4	VOC
Production:										
Small	1	1	2	5.7	1.6	0	2	2	4.7	1.3
Medium	1	1	6	11.2	3.1	0	2	6	10.0	2.8
High	1	4	15	24.9	6.9	0	5	15	25.1	7.0
Trans/Storage:										
Small	1	1	2	4.1	0.1	0	2	2	3.1	0.09
Medium	1	1	6	5.7	0.2	0	2	6	4.6	0.1
High	1	4	15	10.0	0.3	0	5	15	11.6	0.3

[a] HB—continuous high bleed, LB—continuous low bleed, INT—intermittent vent.

Some commenters also disagreed with the costs used for the BSER analysis. One commenter said that the EPA's cost estimates were taken directly from the 2016 White Paper[136] and that the EPA did not update the cost numbers for zero-emission electronic controllers, solar panels, or batteries.[137] The EPA notes that the primary basis for the costs used for the November 2021 analysis was not the White Paper, but rather a 2016 report by Carbon Limits, a consulting company with longstanding experience in supporting efficiency measures in the petroleum industry.[138] One commenter[139] pointed out that Carbon Limits updated their report in early 2022,[140] and recommended that the EPA utilize the more recent information in that report since it included more up-to-date research on zero emissions options for pneumatic controllers. We reviewed the updated 2022 Carbon Limits report and we agree with the commenter that the information presented is well researched and representative of the costs of zero-emission pneumatic controller technologies.

In addition to updating the analysis to reflect the information in the 2022 Carbon Limits report, we also increased the estimate of installation costs and considered operation and maintenance costs for all types of pneumatic controller systems not driven by natural gas.

One commenter mentioned that for zero emission, electrical controller setups, skilled electrical labor is required for wiring, programming, and tuning, which cannot be conducted by lease operators that would otherwise manage this equipment. According to the commenter, one available estimate is as high as $20,000 in labor costs per multi-well pad.[141] In the November 2021 BSER analysis, we assumed that the installation and engineering costs were 20 percent of the total cost of the equipment. For the updated analysis, we increased those costs to 50 percent. The results were installation and engineering costs ranging from $8,500 for a small electrical controller system to almost $52,000 for a large instrument air system.

Another change to the capital cost estimate that the EPA made was to adjust the capital cost to represent the difference in the capital cost between the pneumatic controller system not driven by natural gas and the natural gas-driven controllers that would be used in the absence of a zero emissions requirement. These costs, which were calculated based on $2,227 equipment costs and the $387 installation cost per pneumatic controller, were subtracted from the total capital investment of the pneumatic controller systems not driven by natural gas.

For the November 2021 analysis, the annual costs were estimated as the capital recovery of the original capital investment. This assumed that the operating and maintenance costs for a pneumatic controller system not driven by natural gas was the same as for natural gas-driven controllers. For this analysis, we took into account differences in operating costs. In general, the operating and maintenance costs for pneumatic controller systems not driven by natural gas is less than that of natural gas driven controllers, particularly if the gas is wet gas. To estimate the operating costs for natural gas-driven controllers, we used the average between the wet gas and dry gas cost from the 2022 Carbon Limits report. This resulted in a net savings in the annual operations and maintenance costs for electric and solar-powered controller systems. There are additional operating and maintenance costs

[135] See Document ID No. EPA–HQ–OAR–2021–0317–0749.

[136] U.S. EPA OAQPS. Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel. April 2014.

[137] See Document ID No. EPA–HQ–OAR–2021–0317–0924.

[138] Carbon Limits. (2016) Zero emission technologies for pneumatic controllers in the USA—Applicability and cost effectiveness.

[139] See Document ID No. EPA–HQ–OAR–2021–0317–0844.

[140] Carbon Limits. (2022) Zero emission technologies for pneumatic controllers in the USA Updated applicability and cost effectiveness. Available at *https://cdn.catf.us/wp-content/uploads/2022/01/31114844/Zero-Emissions-Technologoes-for-Pneumatic-Controllers-2022.pdf*.

[141] See Document ID No. EPA–HQ–OAR–2021–0317–0749.

associated with instrument air systems, which resulted in an overall increase in these costs as compared to natural gas-driven controllers.

The costs for electric controllers and instrument air systems assume access to electrical power (that is, access to the grid). Solar-powered controllers can be utilized at remote sites that do not have access to electrical power. Instrument air systems can also be utilized at sites without access to the electricity grid, but these would require the installation and operation of a generator. These generators could be powered by engines fueled by natural gas, diesel, or by solar energy. One commenter provided estimated costs ranging from $60,000 to over $200,000 for an instrument air system driven by a natural gas generator.[142] Using the information provided by the commenter, the EPA estimated costs for the three model plants. Note that the largest model plant contained 20 controllers and the highest cost provided by the commenter was for a site with more than 200 controllers. Therefore, this cost was not utilized. The EPA is specifically requesting more detailed information on the use of generators at sites without access to the grid to power pneumatic controllers, primarily to power instrument air systems. The EPA is also interested in receiving more information on the costs associated with this equipment. Table 24 provides the updated pneumatic controller systems not driven by natural gas costs. This table also provides the costs from the November 2021 analysis for comparison.

TABLE 24—TOTAL CAPITAL AND ANNUAL COSTS FOR PNEUMATIC CONTROLLER SYSTEMS NOT DRIVEN BY NATURAL GAS

Model plant	November 2021 analysis		2022 Updated analysis		
	TCI [a]	TAC [b]	TCI [a]	Adjusted TCI [b]	TAC [c]
Electric:					
Small System	$25,494	$2,799	$25,742	$15,287	$762
Medium System	45,889	5,038	46,335	25,426	959
Solar:					
Small System	28,171	3,093	27,286	16,831	1,112
Medium System	51,242	5,626	49,424	28,515	1,679
Instrument Air System—Grid:					
Small System	not estimated	not estimated	57,966	47,512	9,285
Medium System	not estimated	not estimated	92,335	71,426	10,658
Large System	95,602	10,497	165,550	113,277	14,891
Instrument Air System—Natural Gas Generator:					
Small System	not estimated	not estimated	105,570	95,115	12,604
Medium System	not estimated	not estimated	121,240	100,231	11,914
Large System	not estimated	not estimated	242,850	190,577	19,565

[a] TCI = Total capital investment includes capital cost of equipment plus engineering and installation costs.
[b] Adjusted TCI = Total capital investment minus the cost that would have been incurred if natural gas-driven controllers had been installed.
[c] TAC = Total annual costs including capital recovery (at 7 percent interest and 15-year equipment life) and operation and maintenance costs.

The controllers not driven by natural gas do not emit methane or VOC. Therefore, the emission reductions associated with these systems equal the total emissions shown above in Table 23. The estimated cost effectiveness values for the controllers not driven by natural gas are provided in Table 25. In addition to the cost effectiveness values, Table 25 provides a conclusion regarding whether the estimated cost effectiveness value is within the range that the EPA has typically considered to be reasonable. The ''overall'' reasonableness determination is classified as ''Y'' if the cost effectiveness of either methane or VOC is within the range that the EPA considers reasonable for that pollutant, or ''N'' if both the methane and VOC cost effectiveness values are beyond the range the EPA considers reasonable on a multipollutant basis.

TABLE 25—SUMMARY OF PNEUMATIC CONTROLLER SYSTEMS NOT DRIVEN BY NATURAL GAS COST EFFECTIVENESS FOR NEW SOURCES

Segment/model plant	Cost effectiveness ($/ton) [a]—reasonable?				
	Single pollutant		Multipollutant		Overall [a]
	Methane	VOC	Methane	VOC	
Production:					
Small—Electric controllers—grid	$162–Y	$581–Y	$81–Y	$291–Y	Y
Small—Electric controllers—solar	238–Y	856–Y	119–Y	428–Y	Y
Small—Compressed air—grid	1,969–Y	7,082–N	984–Y	3,541–Y	Y
Small—Compressed air—generator	2,673–N	9,615–N	1,336–Y	4,807–Y	Y
Medium—Electric controllers—grid	96–Y	344–Y	48–Y	172–Y	Y
Medium—Electric controllers—solar	167–Y	602–Y	84–Y	301–Y	Y
Medium—Compressed air—grid	1,062–Y	3,820–Y	531–Y	1,910–Y	Y
Medium—Compressed air—generator	1,187–Y	4,270–Y	594–Y	2,135–Y	Y
Large—Electric controllers—grid	62–Y	222–Y	31–Y	111–Y	Y
Large—Electric controllers—solar	130–Y	467–Y	65–Y	234–Y	Y

[142] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

TABLE 25—SUMMARY OF PNEUMATIC CONTROLLER SYSTEMS NOT DRIVEN BY NATURAL GAS COST EFFECTIVENESS FOR NEW SOURCES—Continued

Segment/model plant	Cost effectiveness ($/ton) [a]—reasonable?				
	Single pollutant		Multipollutant		Overall [a]
	Methane	VOC	Methane	VOC	
Large—Compressed air—grid	593–Y	2,135–Y	297–Y	1,067–Y	Y
Large—Compressed air—generator	780–Y	2,805–Y	390–Y	1,402–Y	Y
Transmission and Storage:					
Small—Electric controllers—grid	247–Y	8,942–N	124–Y	4,471–Y	Y
Small—Electric controllers—solar	364–Y	13,164–N	182–Y	6,582–N	Y
Small—Compressed air—grid	3,015–N	108,939–N	1,507–Y	54,469–N	N
Small—Compressed air—generator	4,093–N	147,891–N	2,046–N	73,946–N	N
Medium—Electric controllers—grid	207–Y	7,474–N	103–Y	3,737–Y	Y
Medium—Electric controllers—solar	362–Y	13,082–N	181–Y	6,541–N	Y
Medium—Compressed air—grid	2,299–N	83,066–N	1,149–Y	41,533–N	N
Medium—Compressed air—generator	2,570–N	92,854–N	1,285–Y	46,427–N	N
Large—Electric controllers—grid	134–Y	4,830–Y	67–Y	2,415–Y	Y
Large—Electric controllers—solar	281–Y	10,156–N	141–Y	5,078–Y	Y
Large—Compressed air—grid	1,285–Y	46,422–N	642–Y	23,211–N	Y
Large—Compressed air—generator	1,688–Y	60,992–N	844–Y	30,496–N	Y

[a] For the production and processing segments, the owners and operators realize the savings for the natural gas that not emitted and lost. The cost effectiveness values shown do not consider these savings. Note that the consideration of savings does not impact whether the cost effectiveness of any of these options falls within the ranges considered reasonable by the EPA.

[b] For overall cost effectiveness to be considered reasonable, either the cost effectiveness of methane or VOC on a single pollutant basis must be within the ranges considered reasonable by the EPA, or the cost effectiveness of both methane and VOC on a multipollutant basis must be within the ranges considered reasonable by the EPA.

iii. Proposed BSER Conclusion.

As demonstrated in the analysis and shown in Table 25, there are pneumatic controller options for controllers not driven by natural gas at sites in the production and transmission and storage segments where the cost effectiveness is within the ranges considered to be reasonable by the EPA. These options can be utilized at sites with access to grid electricity and remote sites that do not have this access. This conclusion is consistent with the findings in the November 2021 proposal.

In addition to these options that use pneumatic controllers not driven by natural gas, there are two types of natural gas-driven controllers that we are proposing as zero-emissions options: (1) Controllers whose emissions are collected and routed to a process, and (2) self-contained natural gas pneumatic controllers. As noted in section IV.D.1.b.i, these natural-gas driven controllers are included in the revised proposed definition of affected facility, meaning that they would be subject to standards to ensure that they are operated and maintained in a manner that ensures zero emissions of methane and VOC. We are including these as compliance options in this proposed action because: (1) they are included as compliance options under several state rules, and (2) there is cursory information indicating that they are utilized in some locations. However, the available information about the prevalence of either of these options at sites in the oil and natural gas production or transmission and storage segments is very limited. Therefore, the EPA is requesting is requesting comment on several issues related to these controllers.

The EPA is interested in several aspects related to the option of collecting the pneumatic controller emissions and routing them to a process. First, we are soliciting information that describes specific situations where owners and operators have utilized this option to use, rather than lose, the valuable natural gas emitted from pneumatic controllers. We are interested in the specific processes and equipment needed, as well as their costs.

Second, our understanding is that routing emissions from pneumatic controllers to a process achieves a 100 percent reduction in emissions. This understanding is based on the fact that the natural gas that is emitted from pneumatic controllers is drawn directly from the raw product gas stream that will be collected and routed to a gathering and boosting station and eventually to a natural gas processing plant (*i.e.,* the gas ''sales line''). Therefore, the emissions from pneumatic controllers are of the same composition as the gas in the sales line. Since the emissions are at atmospheric pressure, it is likely that the gas would need to be compressed prior to re-introduction to the sales line. We do not expect that this compression would result in emissions. Similarly, since the gas composition of these emissions is typically high in methane, the heat content would make it amendable to being used as fuel, or introduced with the primary fuel stream for use in an engine without the need for additional processing that could result in emissions. We are interested in information to support this understanding that routing emissions from pneumatic controllers to a process achieves a 100 percent reduction in emissions.

The 100 percent emissions reductions that we believe can be achieved for controllers contrasts with routing emissions from storage vessels or centrifugal compressor wet seal fluid degassing systems to a process where the emissions are of a different composition from the sales gas. For these situations, a VRU or other treatment is necessary to obtain a gas stream whose composition is suitable to be returned to the sales line or used for another purpose. A VRU often includes a scrubber, separator, condenser, or other component that has a small vent stream emitted to the atmosphere. In addition, the complex nature of VRUs results in the need for maintenance or other situations where the VRU may be bypassed, and emissions vented for short periods of time. Because of both of these situations, the EPA has historically assumed that VRUs achieve a 95 percent reduction or greater in emissions.

The EPA requests information on the assumption that installation of VRUs would not be needed to enable the use of emissions from pneumatic controllers in a process. If there are situations where a VRU is needed, the EPA is interested in the conditions that result in this need, as well as the emissions reduction achieved and the costs.

We are aware of technical limitations of self-contained controllers, namely that their applicability is limited by a number of conditions (*e.g.,* pressure differential, downstream pressure, etc.). The EPA is therefore specifically soliciting information on the frequency of the use of these self-contained controllers in the field, as well as confirmation of specific limitations and costs. We are also interested in information to support our understanding that self-contained controllers achieve 100 percent reduction in emissions when maintained and operated properly.

Several commenters maintain that there are technical limitations that will not allow pneumatic controllers not driven by natural gas to be utilized at sites without electricity, particularly solar-powered controllers.[143] One commenter stated that while the EPA suggested the use of onsite solar generation paired with battery storage as an alternative to grid electricity, such systems are currently ''uncommon, unreliable, and will likely increase the frequency of facility upsets, which will increase safety risks such as overpressure events and spills.'' [144] Another commenter stated that while there may be some pilot projects within the industry, it has not been demonstrated that reliable turnkey packages are available on a widescale basis.[145] Several commenters noted that there are severe geographic limitations to the use of any solar-powered devices. One noted that West Virginia averages only 164 days of sunshine per year, compared with an average of 205 days for the rest of the United States. Even in typically sunny states, operations in canyons or mountain valleys receive significantly limited sunlight exposure. Snow and ice raise additional reliability concerns during winter months.[146] Another commenter stated that large-scale solar applications have not yet been tested in winter months when there is more cloud coverage, increased snow cover, and less sunlight in more northern locations (*e.g.,* Colorado, North Dakota, Idaho, and Wyoming).[147] One industry organization agreed that solar power might be an option but reported that their member companies have not yet been able to demonstrate this to be universally true in Utah's Uinta Basin. This organization cited specific problems such as the requirement of excess generation and battery storage capacity to maintain operations during wintertime inversions and challenges from snowstorms, which could cover the solar panels and inhibit or prevent electricity generation. They conclude that utilizing solar electricity for oil and gas operations in Utah may be labor intensive, costly, and unreliable such that operations would still require backup power from the electric grid or from generators.[148] Another commenter also mentioned that it is probable that supplemental power via natural gas or diesel-powered generators could be required during winter months and/or severe weather events, which would be necessary to ensure a continuous power supply, and, thus, a controlled operation. This commenter also noted that interruptions within the control system pose safety risks to operators and can damage processing equipment, which could potentially lead to excess emissions associated with equipment malfunctions.[149]

One commenter indicated that they were unaware of any operators converting to solar-powered electric controllers at this time. They said while the technology seems promising, many of these solar systems have not yet been proven reliable for all remote locations or facility designs and are not ready for deployment across the country at the large scale that the EPA's proposed rules would require. They note that in 2014, the EPA stated ''solar-powered controllers can replace continuous bleed controllers in certain applications but are not broadly applicable to all segments of the oil and natural gas industry.'' [150]

However, other commenters disagreed and supported the EPA's November 2021 proposal to require zero-emission controllers. Commenters cited several state rules that require all new pneumatic controllers to be non-emitting, including states with colder climates (Colorado). As the EPA also indicated in the November 2021 proposal, there are Canadian provinces that have successfully implemented non-emitting controller regulations. Comments were also provided by vendors that report the successful installation and operation of zero-emission controller systems in a variety of climate conditions.[151] One of these vendors notes the installation of solar-driven instrument air systems in several states, including Wyoming and Colorado.[152]

In a supplement to their 2022 report that was provided in a late comment, Carbon Limits addressed many of the alleged shortcomings of solar and other zero-emitting controller technologies raised in public comments. They state, ''[a]ddressing the queries on the reliability of solar systems for remote locations and cold states, the technology providers and operators interviewed as part of this assessment have solar-powered controllers installed at well sites in remote and cold locations such as Northern Alberta and British Colombia, without major reliability issues. Some of the interviewed technology providers have installed these systems in over 400 well-sites in these states and provinces. The commenter further refers to a statement by the EPA from 2014. However, it is to be noted that solar technology has improved drastically from 2014 to 2021. Efficiency has increased while costs have gone down significantly. Solar-powered controllers are capable of operating at low temperatures and remote locations, among different gas sectors. When it comes to snow cover on panels affecting the performance of solar cells, all the interviewees stated that the panels are placed at a low angle, to catch ample sun in the winter months. Most often, these panels are placed vertically, eliminating snow cover on the solar panels.'' [153] Commenters also indicated that at sites without electricity, owners or operators could install a generator to power an instrument air system.

Under CAA section 111(b), EPA must show that a BSER determination has been ''adequately demonstrated.'' The EPA concludes that zero-emission

[143] See Document ID Nos. EPA–HQ–OAR–2021–0317–0817, EPA–HQ–OAR–2021–0317–0743, EPA–HQ–OAR–2021–0317–0749, and EPA–HQ–OAR–2021–0317–0808.

[144] See Document ID No. EPA–HQ–OAR–2021–0317–0793.

[145] See Document ID No. EPA–HQ–OAR–2021–0317–0599.

[146] See Document ID No. EPA–HQ–OAR–2021–0317–0817.

[147] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

[148] See Document ID No. EPA–HQ–OAR–2021–0317–0740.

[149] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

[150] Oil and Natural Gas Sector Pneumatic Devices, Review Panel, USEPA, OAQPS, 2014: *https://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-devices.pdf.*

[151] See Document ID Nos. EPA–HQ–OAR–2021–0317–0838 and EPA–HQ–OAR–2021–0317–0802.

[152] See Document ID No. EPA–HQ–OAR–2021–0317–0838.

[153] See Document ID No. EPA–HQ–OAR–2021–0317–1451.

pneumatic controller systems that do not use natural gas meet this standard at sites both with and without access to electricity. In addition, as discussed above, we have concluded that there are options available at sites in all segments of the industry that have cost-effective values considered reasonable by the EPA.

Secondary impacts from these non-natural gas-driven, zero-emission controllers, particularly from the use of instrument air systems are indirect, variable, and dependent on the electrical supply used to power the compressor. The 2016 Carbon Limits report indicates that a small instrument air compressor would require around 5 horsepower (HP) of air compression capacity, while a larger facility would require up to 20 HP. Assuming the compressor operates one-half of the total hours in a year, and using an electricity factor of 0.75 HP/kilowatt, the compressor yields an annual electricity usage of around 100 mmBtu/yr for a 5 HP compressor and 400 mmBty/yr for a 20 HP compressor. There would be secondary air pollution impacts associated with the generation of this electricity. The secondary criteria pollutant emissions are estimated to be 7 lbs/yr CO, 60 lbs/yr NO_2, 3 lbs/yr PM, 1 lb/yr $PM_{2.5}$, and 120 lbs/yr SO_2 for a 5 HP compressor and 29 lbs/yr CO, 239 lbs/yr NO_2, 12 lbs/yr PM, 4 lb/yr $PM_{2.5}$, and 478 lbs/yr SO_2 for a 20 HP compressor. The secondary GHG emissions generated as a result of this electricity generation are 20,489 lbs/yr CO_2, 2 lbs/yr methane, and 1lb/yr N_2O for a 5 HP compressor and 81,955 lbs/yr CO_2, 10 lbs/yr methane, and 2 lbs/yr N_2O for a 20 HP compressor. Considering the global warming potential of these GHGs, the total CO_2e emissions would be 20,667 lbs CO_2e from a 5 HP compressor and 82,669 lbs CO_2e from a 20 HP compressor. These total CO_2e would represent a more than 90 percent reduction in the CO_2e emissions when compared to the uncontrolled methane emissions from natural gas driven controllers. No other secondary impacts are expected.

Commenters indicated that at sites without electricity, owners or operators would likely install a generator to power an instrument air system. These commenters contended that relying on a generator would result in emissions of criteria pollutants and carbon monoxide (CO) that could potentially offset the emissions reductions from the methane and VOC. One commenter provided an estimate that a natural gas-fired generator of approximately 200 horsepower would be needed to support reliable operation of a large instrument air system without grid power. This commenter estimated emissions from a generator that size to be 1.94 tpy NO_X, 3.88 tpy of CO, 1.36 tpy of VOC, 0.12 tpy of particulate matter with a diameter of 10 micrometers or less (PM_{10}), 0.14 tpy CH_4 and 730 tpy of CO_2.[154]

The EPA recognizes that if owners and operators elect to comply by installing and operating a generator, there will be secondary emissions generated from the fuel combustion. However, we also point out that, for a site with 100 controllers (a size cited by the commenter requiring a large instrument air system), these secondary emissions would represent approximately a 77 percent decrease in CO_2 equivalent emissions and a 96 percent decrease in VOC emissions from a site with 25 low bleed and 75 intermittent bleed controllers.

In light of the above, we find that the BSER for reducing methane and VOC emissions from natural gas-driven controllers in the production and transmission and storage segments of the industry to be the use of controllers that have a methane and VOC emission rate of zero. This option results in a 100 percent reduction of emissions for both methane and VOC. Therefore, for NSPS OOOOb, we are proposing to require that each pneumatic controller affected facility be designed and operated with a methane and VOC emission rate of zero in the production and transmission and storage segments of the source category, with the following exception for sites in Alaska that do not have access to grid electricity.

In the November 2021 proposal, we determined a separate BSER for the subset of pneumatic controllers, specifically those at sites in Alaska that do not have access to electricity. We also proposed specific requirements for these controllers. We are not proposing any changes to these requirements in this supplemental proposal. Specifically, these sites would be required to use low-bleed controllers (instead of high-bleed controllers) and would be allowed to use high-bleed controllers instead of low-bleed based only upon a showing of functional needs. In addition, we proposed that owners or operators at such sites be required to inspect intermittent vent controllers to ensure they are not venting during idle periods. The rationale for this decision was discussed in the November 2021 proposal (86 FR 63207; November 15, 2021).

The EPA notes that the BSER determination for pneumatic controllers at natural gas processing plants was also not revisited in this supplemental proposal. Therefore, the November 2021 BSER determination of zero emission controllers at natural gas processing plants is retained in this supplemental proposal. The rationale for this decision is contained in the November 2021 proposal (86 FR 63207- 63208; November 15, 2021).

iv. Routing to an Existing Control Device

Several commenters requested that the EPA include an option to collect the emissions from natural gas-driven controllers and route them to a flare or combustion device that achieves 95 percent reduction in methane and VOC. These comments stated that in many situations, an onsite control device already exists and that using it would be a cost-effective method of achieving significant emission reductions.

The EPA acknowledges that this is a viable option to achieve emission reductions from natural gas-driven pneumatic controllers. However, as discussed above, we have determined that BSER for pneumatic controllers is use of one of the several types of controllers that have zero methane and VOC emissions. Thus, routing to an existing control device (*i.e.,* achieving 95 percent reduction) would result in a less stringent standard than the BSER. In the 2021 Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHGI), the estimated methane emissions for 2019 from pneumatic controllers were 700,000 metric tons of methane for petroleum systems and 1.4 million metric tons for natural gas systems. These levels represent 45 percent of the total methane emissions estimated from all petroleum systems (*i.e.,* exploration through refining) sources and 22 percent of all methane emissions from natural gas systems (*i.e.,* exploration through distribution). While we recognize that these emissions include emissions from existing sources, it is clear that pneumatic controllers represent a significant source of methane and VOC emissions. Allowing an option that results in 5 percent more emissions would be a quite significant increase.

The EPA recognizes that there are other instances in the proposed rule where there are options allowed that are less stringent than the measures determined to be BSER. However, in each of these situations, the EPA is convinced that there are genuine technical limitations or safety issues that make compliance with the BSER infeasible. For pneumatic controllers, the EPA maintains that there is a

[154] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

technically feasible option available for all production, processing, and transmission and storage sites, except for sites in Alaska without access to electricity. Therefore, the proposed NSPS OOOOb does not include any alternative non-zero emission standards for pneumatic controllers. The EPA is interested in information that may dispute the conclusion that there is a technically feasible option that does not emit methane or VOC available for all sites in all segments. Some commenters raised concerns about specific situations that may make individual technologies impracticable to implement (*e.g.,* the inability of solar-powered controller systems to meet the needs at certain remote locations that do not have access to electricity). Although the EPA will consider any additional information commenters may submit about such situations, the EPA notes that there are multiple options for meeting the proposed zero-emission standard and that limitations on the use of one technology at any given site does not mean that other options for meeting the standard are unavailable. As a result, the EPA is particularly interested in understanding whether there are site characteristics that would make every zero-emitting option (electric controllers powered by the grid or by solar power; instrument air systems powered by the grid, a generator, or by solar power; collecting the emissions and routing them to a process; self-contained controllers, *etc.*) technically infeasible at the site.

c. Summary of Proposed Standards

In this supplemental proposal, the pneumatic controller affected facility is defined as the collection of natural gas-driven pneumatic controllers at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. This definition applies in all segments of the oil and natural gas source category. Natural gas-driven pneumatic controllers that function as emergency shutdown devices and pneumatic controllers that are not driven by natural gas are exempt from the affected facility, provided that the records are maintained to document these conditions. In addition to the modification definition in 40 CFR 60.14 and the reconstruction definition in 40 CFR 60.15, the proposed rule includes clarification of these terms for the pneumatic controller affected facility. A modification occurs when the number of natural gas-driven pneumatic controllers at a site is increased by one or more, and reconstruction occurs when either the cost of the controllers being replaced exceeds 50 percent of the cost to replace all the controllers, or when 50 percent or more of the pneumatic controllers at a site are replaced.

The proposed standard for pneumatic controller affected facilities is zero emissions of methane and VOC to the atmosphere. An exception to this standard exists for pneumatic controller affected facilities located at sites in Alaska without access to electrical power. The proposed rule does not specify how this emission rate of zero must be achieved, but a variety of viable options are available. All controllers at a site that are not driven by natural gas (*e.g.,* pneumatic controllers driven by compressed air, electric controllers, solar-powered controllers) are not part of the pneumatic controller affected facility, provided that documentation is maintained as previously discussed. If all pneumatic controllers at a site are not natural gas-driven, then there would be no pneumatic controller affected facility at the site, provided the documentation is maintained.

Natural gas-driven controllers can comply with the zero emissions standard by collecting and routing emissions via a CVS to process, or by using self-contained controllers. The proposed rule defines a self-contained pneumatic controller as a natural gas-driven pneumatic controller that releases gas into the downstream piping and not to the atmosphere, resulting in zero methane and VOC emissions.

If you comply by routing the emissions to a process, the CVS that collects the emissions must be routed to a process through a CVS that meets the requirements in proposed 40 CFR 60.5411b, paragraphs (a) and (c). These requirements include certification by a professional or in-house engineer that the CVS was designed properly, and that the CVS is operated with no identifiable emissions as demonstrated through initial and periodic inspections, observations, and measurements. This includes monitoring using OGI at the same frequency as required under the fugitive monitoring program. All issues identified must be corrected. Required records would include the certification and records of all inspections and any corrective actions to repair the defect or the leak.

If you comply by using a self-contained natural gas-driven pneumatic controller, the controller must be designed and operated with no detectable emissions, as demonstrated by conducting initial and quarterly inspections using optical gas imaging. Required records would include records of all inspections and any corrective actions to repair the defect or the leak.

The proposed rule includes an exemption from the zero-emission requirement for pneumatic controllers in Alaska at locations where electrical power is not available. In these situations, the proposed standards require the use of a low-bleed controller (*i.e.,* a controller with a natural gas bleed rate less than or equal to 6 scfh). Records would be required to demonstrate that the controller is designed and operated to achieve a bleed rate less than or equal to 6 scfh. For controllers in Alaska at location without electrical power, the proposed rule includes the exemption that would allow the use of high-bleed controllers instead of low-bleed based on functional needs (including but not limited to response time, safety, or positive actuation). To utilize this exemption, a demonstration of the functional need must be made and submitted in the initial annual report. The proposed rule also includes requirements for natural gas-driven intermittent vent controllers at these sites in Alaska without access to electrical power. Specifically, the proposed rule would require that an intermittent vent not vent to the atmosphere during idle periods. Compliance with this requirement would be demonstrated by modifying the fugitive emissions monitoring plan to include these intermittent vents, monitoring them at the schedule required by the site for the fugitive emissions components affected facility, and repairing any leaks or defects identified. Records would be required of all inspections and repairs.

2. EG OOOOc

The November 2021 proposal defined the pneumatic controller designated facility for EG OOOOc as each natural gas-driven controller. As with the change discussed above for the NSPS OOOOb affected facility, we are also proposing that the EG OOOOc designated facility definition to be the collection of natural gas-driven pneumatic controllers at a well site, centralized production facility, onshore natural gas processing plant, or a compressor station. This definition applies in all segments of the oil and natural gas source category.

In response to comments received and additional information collected, we also updated the BSER analysis for existing sources. The same basic changes were made to the existing source analysis as discussed above for the new source analysis. However, there were a few instances where the emissions and costs differed for existing sources as compared to new. These are discussed in the following sections.

a. Model Plant Emissions

As noted above, for the new source analysis we adjusted the model facilities to remove all high-bleed controllers since NSPS OOOOa and many state rules already prohibit the use of high-bleed controllers. While there are limited instances where states impose this requirement on existing sources, we concluded that the best representation for pneumatic controller model plants was to include one high-bleed for each type of facility. The emissions, calculated using the updated emission factors provided in Table 22, are provided below in Table 26.

TABLE 26—SUMMARY FOR PNEUMATIC CONTROLLER MODEL PLANTS FOR EXISTING SOURCES

Segment/model plant	Number of controllers			Methane emissions (tpy)
	High bleed	Low bleed	Intermittent vent	
Production:				
Small	1	1	2	6.9
Medium	1	1	6	12.2
High	1	4	15	27.3
Transmission and Storage:				
Small	1	1	2	7.4
Medium	1	1	6	9.0
High	1	4	15	15.9

b. Costs for Controllers Not Driven by Natural Gas

There were instances where the estimated costs for the systems for controllers not driven by natural gas were different for existing sources and for new sources. Following are brief descriptions of the reasons for these differences.

For electric and solar-powered controllers, the new source capital costs included the cost for controller valves. For existing sources, we assumed that the existing valves could be used for converting from natural gas pneumatic controllers. For new sites, the cost of natural gas-driven controllers was subtracted from the cost of the controllers not driven by natural gas, as those capital expenses would be "saved." This adjustment was not made for existing sources. We assumed that the relative engineering and installation costs would be higher at an existing site; therefore, we assume an engineering and installation cost of 100 percent of the capital costs. For instrument air systems, the new site costs included costs for the new controllers, while the assumption was that existing sources could continue to use the existing controllers that were formerly driven by natural gas. The instrumentation cost for a retrofit for an existing site was assumed to be 40 percent higher than for a new site, and the engineering and installation costs were assumed to be 100 percent of the capital costs for existing sites (as opposed to 50 percent for new sites). As with electric and solar-powered controllers, the cost of the natural gas-driven controllers not needed was not subtracted from the existing source capital costs.

The operation and maintenance costs for existing sources used were the same as for new sources. Therefore, the only difference in total annual costs was due to the difference in the capital recovery costs because of the different total capital investment.

Table 27 compares the total capital investment and total annual cost for new sources and existing sources for each model plant and zero emission controller technology.

TABLE 27—COMPARISON OF TOTAL CAPITAL AND ANNUAL COSTS FOR NON–EMITTING CONTROLLERS NOT DRIVEN BY NATURAL GAS AT NEW AND EXISTING SOURCES

Model plant	New sources		Existing sources	
	Adjusted TCI [a b]	TAC [c]	TCI [a]	TAC [c d]
Electric:				
Small System	$15,287	$762	$20,593	$1,345
Medium System	25,426	1,112	34,322	1,936
Large System	55,842	1,550	75,508	3,709
Solar:				
Small System	16,831	959	22,653	1,761
Medium System	28,515	1,679	38,441	2,768
Large System	63,049	3,258	85,119	5,681
Instrument Air System—Grid:				
Small System	47,512	9,285	58,636	10,506
Medium System	71,426	10,658	76,481	11,213
Large System	113,277	14,891	127,469	16,449
Instrument Air System—Generator:				
Small System	95,115	12,604	120,000	15,337
Medium System	100,231	11,914	120,000	14,085
Large System	190,577	19,565	220,000	22,795

[a] TCI = Total capital investment includes capital cost of equipment plus engineering and installation costs.
[b] Adjusted TCI = Total capital investment minus the cost that would have been incurred if natural gas-driven controllers had been installed.
[c] TAC = Total annual costs including capital recovery (at 7 percent interest and 15-year equipment life) and operation and maintenance costs.
[d] For the production segment, the owners and operators realize the savings for the natural gas that not emitted and lost. The cost values shown do not consider these savings.

c. Existing Source BSER Determination

Table 28 shows the cost effectiveness values for methane of the controller technologies that are not driven by natural gas and that do not emit methane.

TABLE 28—SUMMARY OF PNEUMATIC CONTROLLER SYSTEMS NOT DRIVEN BY NATURAL GAS METHANE COST EFFECTIVENESS FOR EXISTING SOURCES

Segment—model plant	Cost effectiveness [a] ($/ton methane reduced)	Reasonable?
Production Segment:		
Small—Electric controllers—grid	$195	Y
Small—Electric controllers—solar	255	Y
Small—Compressed air—grid	1,524	Y
Small—Compressed air—generator	2,225	N
Medium—Electric controllers -grid	158	Y
Medium—Electric controllers—solar	227	Y
Medium—Compressed air—grid	918	Y
Medium—Compressed air—generator	1,153	Y
Large—Electric controllers -grid	136	Y
Large—Electric controllers—solar	208	Y
Large—Compressed air—grid	603	Y
Large—Compressed air—generator	836	Y
Transmission and Storage Segment:		
Small—Electric controllers—grid	181	Y
Small—Electric controllers—solar	238	Y
Small—Compressed air—grid	1,418	Y
Small—Compressed air—generator	2,069	Y
Medium—Electric controllers -grid	216	Y
Medium—Electric controllers—solar	309	Y
Medium—Compressed air—grid	1,250	Y
Medium—Compressed air—generator	1,571	Y
Large—Electric controllers -grid	233	Y
Large—Electric controllers—solar	357	Y
Large—Compressed air—grid	1,033	Y
Large—Compressed air—generator	1,432	Y

[a] For the production segment, the owners and operators realize the savings for the natural gas that not emitted and lost. The cost effectiveness values shown do not consider these savings. Note that the consideration of savings does not impact whether the cost effectiveness of any of these options falls within the ranges considered reasonable by the EPA.

As shown in Table 28, all options evaluated, with the exception of an instrument air system driven by a generator at a small model plant, have cost effectiveness values within the range that the EPA considers reasonable for methane.

Further, as discussed at length above in section IV.D.1.b.iii, the EPA finds that these controller technologies not driven by natural gas are technically feasible in locations with and without electrical power. Owners and operators can use natural gas-driven low or high bleed controllers or intermittent controllers, provided the emissions are collected and routed through a CVS to a process. Finally, owners and operators have the option of using natural gas-driven self-contained controllers.

Secondary impacts from these options, particularly from the use of instrument air systems, are indirect, variable, and dependent on the electrical supply used to power the compressor. As discussed above, this would result in an increase in electricity needs and minimal emission increases. As discussed above, the use of a generator to power an instrument air system will result in emissions of two criteria pollutants—CO and CO_2. However, the comparison in the CO_2 equivalent emissions shows that even with the secondary emissions from the generator, there is a substantial reduction in CO_2 equivalent emissions.

In light of the above, we find that the BSER for reducing methane emissions from existing natural gas-driven controllers in the production and transmission and storage segments of the industry to be the use of controllers that have a methane emission rate of zero. This option results in a 100 percent reduction of emissions of methane. Therefore, for EG OOOOc, we are proposing to require that each pneumatic controller affected facility be designed and operated with a methane emission rate of zero for all pneumatic controllers in the production and transmission and storage segments of the source category, with the exception discussed below.

As discussed above for new sources, we did not re-evaluate BSER for sites in Alaska that do not have access to electricity and are proposing the same requirements as in the November 2021 proposal. Similarly, we did not re-evaluate BSER for pneumatic controllers at existing natural gas processing plants. Therefore, the November 2021 BSER determination of zero-emission controllers at natural gas processing plants is retained in this supplemental proposal.

The proposed standards and other requirements for existing pneumatic controller designated facilities under EG OOOOc are the same as described above for new pneumatic controller affected facilities under the NSPS OOOOb.

d. Additional Comments

There were two additional topics raised in the public comments that are discussed in this section: (1) The potential exemption of small sites with low production and/or a low number of controllers, and (2) issues associated with the supply chain.

i. Small Site Exemptions.

Several commenters requested that the EPA include an exemption for small sites with low production and/or a low number of pneumatic controllers. The commenters provided a range of pneumatic controllers that they felt represented a reasonable cut-off, ranging from 3 to 30 controllers.

The EPA notes that the cost effectiveness values for the smallest model plant, which includes 1 high-bleed, 1 low-bleed, and 2 intermittent vent controllers, were $181 and $238 per ton of methane reduced for electric controllers and solar controllers, respectively. These cost effectiveness values are well within the ranges considered to be reasonable by the EPA. We also performed an analysis of the cost effectiveness of the use of electric controllers and solar-powered controllers at sites with a single controller. For sites with only one high-bleed controller, the cost effectiveness was estimated to be $379 and $437 per ton of methane reduced for electric and solar-powered controllers, respectively. For a site with one intermittent vent controller, the cost effectiveness values were estimated as $913 per ton for electric controllers, and $1,053 per ton for solar-powered controllers. For a site with one low-bleed controller, the cost effectiveness values were $1,181 per ton for electric controllers and $1,363 per ton for solar-powered controllers. As all of these cost effectiveness values are within the range considered reasonable for methane by the EPA, this analysis does not support an exemption for sites with low numbers of pneumatic controllers.

One commenter stated that even at the current prices for natural gas, it would take the average low-production natural gas well about six years of all of its profits to pay for the electric grid option and more than that for the solar option. The commenter added that for a Pennsylvania well site, the time period would be 70 or more years.[155] This commenter did not provide details of their analysis. While the EPA recognizes that that impacts on profitability are generally not considered in determining BSER, we are interested in the details of the analysis of profit margins at low production wells. Specific to this information provided by the commenter, dividing the total estimated capital investment of an electric controller system for the small model plant ($20,593) by six years results in $3,400 per year. If it is assumed that this capital investment is financed for six years at a 7 percent interest rate, this cost would be around $4,300 per year, which equates to around $360 per month. The EPA is interested in learning whether this amount represents typical profit margins for low production wells.

Another commenter added that the cost of converting to an electronic controller or instrument air system will likely result in the shut-in of many small, low-production well sites. These sites have a remaining useful life that will be cut short by the proposed rule's pneumatic controller requirements.[156]

The EPA notes that the implementing regulations for emission guidelines contained in 40 CFR part 60, subpart Ba include provisions that allow states to develop a less stringent standard taking into consideration factors such as the remaining useful life of such source. For more information on remaining useful life and other factors considerations, see section V.C of this preamble.

ii. Supply Chain Issues

In light of the proposal to require zero-emission pneumatic controllers for both new and existing sources, the EPA would like to address several comments it received and solicit related information. One commenter predicted that the requirements will likely generate supply chain shortages and the small operators will be last to procure the necessary equipment at the highest price.[157] Another commenter stated that the EPA has not adequately considered the impacts of the current supply chain interruptions on the ability of operators to comply with the rule. Specialized equipment, such as air compressors, electric controllers, and equipment needed to retrofit facilities have been particularly hard-hit by supply chain constraints related to COVID–19. This commenter reported that owners and operators have already experienced delays of several months in acquiring equipment to retrofit facilities to instrument air, all prior to the EPA proposal, and that the increased demand for that equipment given proposed rule requirements would only exacerbate the challenges associated with acquiring that equipment.[158] For existing sources, the EPA points out that several years will pass between the time EG OOOOc is finalized and the compliance dates for state rules, thus allowing a substantial amount of time for adjustments in the supply chain. While the commenters primarily focused on potential supply chain issues related to requiring the conversion to zero emissions controllers at existing sources, the EPA also understands that the promulgation of NSPS OOOOb could also result in a spike in the demand. In light of these comments, the EPA is specifically requesting additional comment on the availability of zero-emission pneumatic controller systems not powered by natural gas due to supply chain constraints or other reasons.

E. Pneumatic Pumps

A pneumatic pump is a positive displacement reciprocating unit generally used by the Oil and Natural Gas Industry for one of four purposes: (1) Hot oil circulation for heat tracing/freeze protection, (2) chemical injection, (3) moving bulk liquids, and (4) glycol circulation in dehydrators. There are two basic types of pneumatic pumps used in the Oil and Natural Gas Industry—diaphragm pumps and piston pumps. Natural gas-driven pneumatic pumps emit methane and VOCs as part of their normal operation. Detailed information on pneumatic pumps, including their functions, operations, and emissions, is provided in the preamble for the November 2021 proposal (86 FR 63224–63226; November 15, 2021).

1. NSPS OOOOb

a. November 2021 Proposal

In the November 2021 proposal, a pneumatic pump affected facility was defined as each natural gas-driven diaphragm or piston pump in any segment of the source category. The proposed definition of an affected facility excluded lean glycol circulation pumps that rely on energy exchange with the rich glycol from the contractor.

For pneumatic pumps in the production and transmission and storage segments, the November 2021 proposal would have required that the emissions be routed to an existing control device that achieves 95 percent control of methane and VOCs, or to route the emissions to an existing VRU and to a process. This proposed standard would have covered both diaphragm and piston pumps. The proposed rule did not propose to require that a new control device be installed. At natural gas processing plants, the proposed rule would have required the prohibition of methane and VOC emissions from pneumatic pumps.

The BSER analysis that led to the November 2021 proposed pneumatic pump requirements for the production

[155] See Document ID No. EPA–HQ–OAR–2021–0317–0814.

[156] See Document ID No. EPA–HQ–OAR–2021–0317–0777.

[157] See Document ID No. EPA–HQ–OAR–2021–0317–0814.

[158] See Document ID No. EPA–HQ–OAR–2021–0317–0743.

and transmission segments concluded that the cost effectiveness for routing to an existing control device was reasonable. The EPA also concluded that it was not cost-effective to require the owner or operator of a pneumatic pump to install a new control device or process onsite to capture emissions solely for this purpose.

The EPA also evaluated pneumatic pumps that are not powered by natural gas. Specifically, the types of pumps evaluated were electric pumps, solar-powered pumps, and pumps powered by compressed air. We found that the cost-effectiveness of these options, for both diaphragm and piston pumps, were generally within the ranges that the EPA considers reasonable. However, for instrument air systems and electric pumps, our analysis assumed that electrical power was available onsite. We noted that commenters have raised concerns in the past regarding solar-powered pneumatic pumps, which have technical limitations that do not make them universally feasible for locations without access to electrical power. In November 2021, we did not have information that such limitations had been overcome, and we were therefore unable to conclude that pumps not driven by natural gas represented BSER at that time. We solicited comment on this issue to better understand whether options that do not use natural gas are technically feasible at sites without electrical power. We also solicited comment on an approach that would subcategorize pneumatic pumps located at production and transmission and storage sites based on availability of electricity and would then set separate standards for each subcategory.

Since all natural gas processing plants have access to electrical power, we only evaluated compressed air systems for this segment. The cost effectiveness of these systems was found to be in the range considered to be reasonable by the EPA, and we therefore concluded that BSER was pneumatic pumps that are not driven by natural gas.

b. Changes to Proposal and Rationale

The proposed NSPS OOOOb requirements in this supplemental proposal differ from the November 2021 proposal in several ways, starting with the affected facility definition. As noted above, in the November 2021 proposal, a pneumatic pump affected facility was defined as each natural gas-driven pneumatic pump. In this supplemental proposal, a pneumatic pump affected facility is defined as the collection of all natural gas-driven pneumatic pumps at a site.

After considering comments on the emissions standards, as well as the information submitted in response to our specific solicitations for information, the EPA is now proposing a zero-emissions standard for pneumatic pump affected facilities in all segments of the industry. Specifically, the EPA is proposing that pneumatic pumps not driven by natural gas be used. This is a significant change from the November 2021 proposal, which would have required that emissions from pneumatic pump affected facilities be routed to control or to a process, but only if an existing control or process was on site.

The proposed rule recognizes that at sites without access to electricity, there could be situations where it is technically infeasible to use a pump that is not driven by natural gas. As a result, the EPA is proposing to include a tiered structure in the rule that would allow flexibility based on site-specific conditions. At sites without access to electricity, if a demonstration is made that it is technically infeasible to use a pneumatic pump that is not driven by natural gas, the rule would allow the use of a natural gas-driven pump, provided that the emissions are captured and routed to a process, which EPA understands to achieve 100 percent reduction of methane and VOC. Such an infeasibility determination is not allowed if the site has access to electricity. This means the proposed rule would prohibit the use of natural gas-driven pumps at sites with access to electricity.

At sites without access to electricity for which the owner or operator has demonstrated that it is technically infeasible to utilize a pneumatic pump not driven by natural gas, an owner or operator may also demonstrate that it is technically infeasible to capture the pneumatic pump's emissions and route them to a process. Where routing to a process is infeasible, the resulting requirement for emissions control depends on the number of natural gas-driven diaphragm pumps at the site. If there are four or more natural gas-driven pumps at the site, the proposed rule would require that the emissions from all pumps at the site be collected and be routed to a control device that achieves 95 percent reduction of methane and VOC. If there are less than four natural gas-driven diaphragm pumps at the site without access to electricity, the proposed requirements for pumps at the site would be the same as in the November 2021 proposal, *i.e.,* route to an existing control device that achieves 95 percent emissions reductions.

Details on the proposed pneumatic pump requirements are provided in section IV.D.1.c. The following sections provide the rationale for the significant changes discussed in this section.

i. Changes to Affected Facility, Modification, and Reconstruction

As previously noted, the pneumatic pump affected facility definition changed from being a single pump in the November 2021 proposal to the collection of pumps at a site in this supplemental proposal. In this supplemental proposal, a pneumatic pump affected facility is defined as the collection of all natural gas-driven pneumatic pumps at a site. As we advanced our evaluation of the control measures to reduce methane and VOC emissions from pneumatic pumps, it became apparent that most of the measures to reduce or eliminate emissions are site-wide solutions. For instance, a compressed air system installed at a site would be used to power all pneumatic pumps at the site, not just one, which would alleviate the need for a separate system for each pump. In fact, the cost analysis for the November 2021 proposed rule for compressed air systems was conducted on a ''model plant'' site-wide basis. Similarly, emissions from all pumps at a site would be routed to a single control device and would therefore not require the installation of a control device for each pump. We are specifically soliciting comment on this proposed change to the definition of a pneumatic pump affected facility from an individual pump to the collection of all natural gas-driven pneumatic pumps at a site.

In addition, some of the means of powering a pneumatic pump without the use of natural gas can also be used to power pneumatic controllers. While our updated BSER analyses for pneumatic pumps and pneumatic controllers evaluated the cost effectiveness of these sources independently, the shared usage of solutions for the two sources, such as compressed air systems, solar-powered systems, or generators, will result in even lower overall site-wide cost effectiveness values.

Under the previous approach in which EPA assessed each pump on an individual basis, the installation or replacement of a pneumatic pump would have resulted in the pump being a new source and an affected facility subject to NSPS OOOOb. In 40 CFR 60.14(a), modification is defined as ''any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant.'' In order to clarify what constitutes a modification for the collection of all pneumatic pumps at a site, the supplemental proposed rule specifies that if one or more pneumatic pumps is added to the site such that the total number of pumps increases, such addition constitutes a modification because it represents a physical change that results in an increase in emissions. Therefore, the collection of pneumatic pumps at the site would become a pneumatic pump affected facility. The EPA believes that owners and operators will implement zero-emission pumps across a site when a modification occurs because converting a single zero-emitting device typically requires a conversion of all devices at the facility. The EPA solicits comment on the ways in which a modification to a pneumatic pump affected facility would occur in light of the affected facility definition proposed herein, which includes the collection of all natural gas-driven pneumatic pumps at a site.

Analogous to the discussion above regarding reconstruction for pneumatic controllers in section IV.D.1.b.i, the definition of the pneumatic pump affected facility is the collection of natural gas-driven pneumatic pumps at a site. As with pneumatic controllers, the cost that would be required to construct a ''comparable entirely new facility'' under 40 CFR 60.15(b)(1) would be the cost of replacing all existing pumps with new pumps. Because individual pumps are likely to have comparable replacement costs, it is reasonable to assume that there would be a one-to-one correlation between the percentage of pumps being replaced at a site and the percentage of the fixed capital cost that would be required to construct a comparable entirely new facility.

Accordingly, we are proposing to include a second, simplified method of determining whether a pump replacement project constitutes reconstruction under 40 CFR 60.15(b)(1) whereby reconstruction may be considered to occur whenever greater than 50 of the number of existing onsite pumps are replaced.[159] As with controllers, the EPA believes that allowing owners or operators to determine reconstruction by counting the number of pumps replaced is a more straightforward option than requiring owners and operators to provide cost estimate information. By providing this option, the EPA intends to reduce the administrative burden on owners and operators, as well as on the implementing agency reviewing the information. Owners and operators would be able to choose whether to use the cost-based criterion or the proposed number-of-pumps criterion. No matter which option an owner or operators chooses to use, the remaining provisions of 40 CFR 60.15 apply—namely, 40 CFR 60.15(a), the technological and economical provision of 40 CFR 60.15(b)(2), and the requirements for notification to the Administrator and a determination by the Administrator in 40 CFR 60.15(d), (e) and (f). The EPA is proposing that the standard in 40 CFR 60.15(b)(1) specifying that the ''fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility'' can be met through a showing that 50 percent or more of the number of existing onsite pumps are replaced. Therefore, upon such a showing, an owner or operator may demonstrate compliance with the remaining provisions of 40 CFR 60.15 that reference the ''fixed capital cost'' criterion.

The same logic and rationale discussed above in section IV.D.1.b.i for applying a 2-year rolling aggregation period for controller replacements also applies for pneumatic pumps. Therefore, we are proposing the same 2-year rolling period as the appropriate aggregation period to define a proposed replacement program time frame. Thus, the EPA proposes to count toward the greater than 50 percent reconstruction threshold all pumps replaced pursuant to all continuous programs of reconstruction which commence (but are not necessarily completed) within any 2-year rolling period following proposal of these standards. In the Administrator's judgment, the 2-year rolling period provides a reasonable method of determining whether an owner of an oil and natural gas site with pneumatic pumps is actually proposing extensive controller replacement, within the EPA's original intent in promulgating 40 CFR 60.15. As explained in greater detail in section IV.D.1.b.i, the EPA is soliciting comment on several aspects of the proposed reconstruction definition for pneumatic pumps and pneumatic controllers and refers commenters to that section for a description of the specific information requested.

The following scenarios are examples of the application of these proposed requirements for a site with access to electricity that has four natural gas-driven pneumatic pumps. Scenario 1—One of the four pumps is replaced at any given time. The collection of pumps at the site would not be a pneumatic pump affected facility as this action is not a modification or reconstruction. Scenario 2—Three of the four pumps are replaced at the same time. This would constitute reconstruction (replacement of greater than 50 percent of the pumps), so the four pumps (*i.e.,* the ''collection'' of pumps at the site) would be a pneumatic pump affected facility. This affected facility would then be subject to the zero emissions standard, meaning that all pumps at the site, including the three new pumps and the one existing pump, cannot be driven by natural gas. Under Scenario 2, the one existing pump would need to be replaced or converted so that it is not powered by natural gas. Scenario 3—one pneumatic pump is replaced in February and two more are replaced in December of the same year. This would represent reconstruction (because more than 50 percent of the total number of pumps are being replaced over a 2-year period), so the four pumps (*i.e.,* the ''collection'' of pumps at the site) would be a pneumatic pump affected facility at the time the two pumps were replaced in December. This affected facility would then be subject to the zero-emissions standard, meaning that all four pumps would not be allowed to be driven by natural gas. Scenario 4—An additional pneumatic pump is added at any given time. This addition would represent a modification since it represents a physical change and would result in an increase in emissions. The five pumps would be a pneumatic pump affected facility and all five pumps would need to be powered in a manner other than natural gas.

ii. Changes to the Standard

As discussed above, we solicited comment in the November 2021 proposal on two key issues related to the proposed standard and BSER determination. These were: (1) An approach that would involve subcategorizing pneumatic pumps located at production and transmission and storage segments based on availability of electricity, and then developing separate standards for each subcategory, and (2) the technical feasibility of using pneumatic pumps not powered by natural gas at sites without electrical power.

Regarding the first issue, several commenters supported the approach of subcategorizing based on access to electrical power, and then determining BSER for pneumatic pumps separately for sites with and without access to

[159] Adding this method of determining ''reconstruction'' for pneumatic pumps is in accordance with 40 CFR 60.15(g), which states that ''[i]ndividual subparts of this part [''Reconstruction''] may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.''

electrical power. One of these commenters noted that the availability of electricity is a significant and constraining factor that is within the EPA's authority to consider in subcategorization.[160]

The comments were mixed concerning the feasibility of options that do not use natural gas-driven pneumatic pumps at remote sites without access to electrical power. Several commenters maintain that zero-emission pneumatic pumps are technically infeasible at sites without electricity. For example, one commenter who voiced support for the use of non-natural gas driven pumps as an option at sites where it is technically feasible indicated that requiring these pumps at many of their remote sites would be ''burdensome at best and would force site shutdown in many cases.'' [161] Another commenter stated that onsite solar generation paired with battery storage as an alternative to grid electricity systems are currently uncommon and unreliable. According to the commenter, use of these systems would likely increase the frequency of facility upsets, which would increase safety risks such as overpressure events and spills. The commenter concluded that onsite solar should therefore not be deemed an available technology.[162] Other commenters provided specific examples of where pneumatic pumps not driven by natural gas, particularly solar-powered pumps, would likely not be technically feasible. Examples of the situations cited included locations with very cold temperatures, extended periods of cloud cover, and heavy snow load.

However, many commenters reported that options that do not use natural gas-driven pneumatic pumps are available at sites without access to grid electricity systems, and that their use has been demonstrated. One of these commenters noted that in addition to solar-powered pumps, thermal electric generators or methanol fuel cells have been used to increase power at sites with high demand.[163] Another commenter is aware of retrofits at remote locations that have no electrical power in which natural gas is used to generate electricity to run pumps directly or to power air compressors that drive pneumatic pumps.[164] The EPA is requesting information regarding the characteristics of sites where thermal electric generators, methanol fuel cells, or other means to boost power for solar driven pneumatic pumps are needed. The EPA is also interested in costs for those systems.

Two commenters, who are also equipment vendors, confirmed the successful implementation of technologies to utilize pneumatic pumps not driven by natural gas at remote locations without the access to the grid. One has deployed solar-driven pneumatic pumps and air compressors in many states throughout the southwestern and northwestern U.S., including a remote location in Wyoming that experienced temperatures down to minus 11 degrees Centigrade (°C).[165] The second vendor reported that their standalone power generators have been deployed at a number of sites across the country to power pneumatic pumps.[166]

In our analysis for the November 2021 proposal, we evaluated the costs and impacts of electric pumps run from the grid, solar-powered pumps, and compressed air systems to power the pumps. No significant comments were received on this 2021 analysis; therefore, the essential elements of the analysis and results remain the same.

Baseline Emissions. The baseline emission estimates were calculated assuming a bleed rate of 2.48 scfh for natural gas-driven piston pumps and 22.45 scfh for natural gas-driven diaphragm pumps. Based on these natural gas bleed rates, assuming that natural gas bleeds from the pump for 8,760 hours per year and using the segment-specific gas compositions developed during the 2012 NSPS, the baseline emissions were estimated as provided in Table 21. More information on these calculations is provided in the Technical Support Document for this rulemaking.

The baseline emission analysis was conducted for six representative sites: (1) A single diaphragm pump, (2) a single piston pump, (3) one diaphragm pump and one piston pump, (4) two diaphragm pumps and two piston pumps, (5) 10 diaphragm pumps and 10 piston pumps, and (6) 50 diaphragm pumps and 50 piston pumps. All representative sites were not evaluated for all three sectors, as it is not expected that they would be applicable. Specifically, the two largest sites with 10 and 100 total pumps were not evaluated for the production and transmission and storage segments. For the processing plant segment, since it is expected that multiple pumps would be at each site, only representative sites 4, 5, and 6 were evaluated. The following table provides the baseline emissions for each type of representative facility.

TABLE 29—BASELINE PNEUMATIC PUMP EMISSIONS (TONS PER YEAR) FOR REPRESENTATIVE SITES

Rep Site #	# of Pumps		Production		Processing		Transmission/storage	
	Diaphragm	Piston	Methane	VOC	Methane	VOC	Methane	VOC
1	1	0	3.46	0.96	n/a		4.5	0.125
2	0	1	0.38	0.11	n/a		0.50	0.014
3	1	1	3.84	1.07	n/a		5.0	0.14
4	2	2	7.68	2.14	7.68	2.14	10.0	0.28
5	10	10	n/a		38.4	10.7	n/a	
6	50	50	n/a		192.0	53.4	n/a	

Cost Analysis for Options That Do Not Use Natural Gas-Driven Pneumatic Pumps. The EPA evaluated the following pump options that do not use natural gas: electric pumps, solar-powered pumps, and instrument air systems that produce compressed air to power the pumps. All three options were evaluated for pneumatic pumps in the production and transmission and storage segments. For the processing segment, only instrument air systems

[160] See Document ID No. EPA–HQ–OAR–2021–0317–0938.

[161] See Document ID No. EPA–HQ–OAR–2021–0317–0463.

[162] See Document ID No. EPA–HQ–OAR–2021–0317–0793.

[163] See Document ID No. EPA–HQ–OAR–2021–0317–0844.

[164] See Document ID No. EPA–HQ–OAR–2021–0317–0765.

[165] See Document ID No. EPA–HQ–OAR–2021–0317–0838.

[166] See Document ID No. EPA–HQ–OAR–2021–0317–0823.

were evaluated because it is expected that all processing plants have access to electrical power and have multiple pumps at the site.

The following paragraphs provide the estimated costs for electric pumps, solar-powered pumps, and instrument air systems. The EPA is not aware of differences between the oil and natural gas industry segments that would result in the different costs for these options between segments. These paragraphs provide capital costs and total annual costs. For all of these options, the capital recovery cost component of the annual cost is based on a 7 percent interest rate and an equipment life of 10 years.

The capital and installation cost of an electric pump using electricity from the grid is estimated to be $5,219. The total annual costs, including capital recovery and an estimated operation and maintenance cost of $329 per year, yields a total annual cost per electric pump of $1,072.

For solar-powered pumps, the estimated capital cost, including installation, is $2,501 per pump. It is assumed that the annual operation and maintenance is no greater than a natural gas-driven pump, so the total annual cost is the capital cost of $356 per year.

For electric pumps and solar-powered pumps, the cost information is assessed on an individual pump basis. While it is expected that the cost per pump would be less where there are more pumps on site, we do not have information on these cost advantages. Therefore, our estimate of the site-wide costs and emission reductions would simply be the multiple of our per pump costs and emission reductions multiplied by the number of pumps at the site. Thus, the cost effectiveness for representative sites 3 and 4 is the same. The EPA is requesting information on the costs of site-wide electric and solar-powered pump solutions.

Instrument air system costs were estimated for small, medium, and large compressors. The small compressor was assumed to have an air capacity of 135 scfh, while the medium and large had capacities of 562 and 1,350 scfh, respectively. The estimated capital (including installation) costs for these three sizes of instrument air systems are $6,742 for the small system, $33,699 for the medium system, and $59,308 for the large system. The estimated annual costs, including capital recovery, labor for operation and maintenance, and electricity, are $11,295 for the small system, $36,264 for the medium system, and $81,350 for the large system. In the estimation of impacts for the representative sites described above, the small system costs were used for representative sites 1, 2, 3, and 4; the medium system for representative site 5; and the large system for representative site 6.

Since all of these options do not use natural gas to drive the pneumatic pump, their use results in a 100 percent reduction in methane and VOC emissions from the baseline levels shown in Table 21 above. Using the annual total annual costs and these emission reductions, we calculated the cost effectiveness for each zero-emission option for each representative site. Cost effectiveness was calculated on a single pollutant basis, where the total annual cost was applied entirely to the reduction of each pollutant. Cost effectiveness was also calculated on a multi-pollutant basis, where half the cost of control is assigned to the methane reduction and half to the VOC reduction.

The estimated cost effectiveness values for the options that do not use natural gas-driven pneumatic pumps are provided in Table 30. In addition to the cost effectiveness values, Table 30 provides a conclusion as to whether the estimated cost effectiveness value is within the range that the EPA has typically considered to be reasonable. The ''overall'' reasonableness determination is classified as ''yes'' if the cost effectiveness of either methane or VOC is within the range that the EPA considers reasonable for that pollutant, or if both the methane and VOC cost effectiveness values are without the range that the EPA considers reasonable on a multipollutant basis.

TABLE 30—SUMMARY OF COST EFFECTIVENESS FOR PNEUMATIC PUMP OPTIONS THAT DO NOT USE PUMPS DRIVEN BY NATURAL GAS

Segment Option—Representative Site	Cost Effectiveness ($/ton) [a]—Reasonable?				Overall [a]
	Single pollutant		Multipollutant		
	Methane	VOC	Methane	VOC	
Production Segment:					
Electric Pumps—Single Diaphragm.	$310–Y	$1,115–Y	$115–Y	$557–Y	Y
Electric Pumps—Single Piston.	1,632–Y	5,869–Y	816–Y	2,934–Y	Y
Electric Pumps—Multiple Pumps[b].	441–Y	1,585–Y	220–Y	793–Y	Y
Solar Pumps—Single Diaphragm.	103–Y	370–Y	51–Y	185–Y	Y
Solar Pumps—Single Piston.	937–Y	3,371–Y	469–Y	1,686–Y	Y
Solar Pumps—Multiple Pumps[b].	185–Y	667–Y	93–Y	334–Y	Y
Instrument Air—Single Diaphragm.	3,264–N	11,743–N	1,632–Y	5,871–Y	Y
Instrument Air—Single Piston.	29,724–N	106,921–N	14,682–N	53,461–N	N
Instrument Air—1 Diaphragm/1 Piston.	2,941–N	10,581–N	1,471–Y	5,290–Y	Y
Instrument Air—2 Diaphragm/2 Piston.	1,471–Y	5,290–Y	735–Y	2,645–Y	Y

TABLE 30—SUMMARY OF COST EFFECTIVENESS FOR PNEUMATIC PUMP OPTIONS THAT DO NOT USE PUMPS DRIVEN BY NATURAL GAS—Continued

Segment Option—Representative Site	Cost Effectiveness ($/ton) [a]—Reasonable?				Overall [a]
	Single pollutant		Multipollutant		
	Methane	VOC	Methane	VOC	
Processing Segment:					
Instrument Air—2 Diaphragm/2 Piston.	1,471–Y	5,290–Y	735–Y	2,645–Y	Y
Instrument Air—10 Diaphragm/10 Piston.	944–Y	3,397–Y	472–Y	1,699–Y	Y
Instrument Air—50 Diaphragm/50 Piston.	424–Y	1,524–Y	212–Y	762–Y	Y
Transmission and Storage Segment:					
Electric Pumps—Single Diaphragm.	237–Y	8,563–N	119–Y	4,281–Y	Y
Electric Pumps—Single Piston.	1,249–Y	45,083–N	624–Y	22,541–N	Y
Electric Pumps—Multiple Pumps [b].	337–Y	12,177–N	169–Y	6,088–N	Y
Solar Pumps—Single Diaphragm.	79–Y	2,844–Y	39–Y	1,422–Y	Y
Solar Pumps—Single Piston.	717–Y	25,897–N	359–Y	12,948–N	Y
Solar Pumps—Multiple Pumps[b].	142–Y	5,125–Y	71–Y	2,563–Y	Y
Instrument Air—Single Diaphragm.	2,499–N	90,206–N	1,249–N	45,103—N	N
Instrument Air—Single Piston.	22,751–N	821,348–N	11,376–N	410,674–N	N
Instrument Air—1 Diaphragm/1 Piston.	2,251–N	81,279–N	1,126–Y	40,640–N	N
Instrument Air—2 Diaphragm/2 Piston.	1,126–Y	40,640–N	563–Y	20,320–N	Y

[a] For the production and processing segments, the owners and operators realize the savings for the natural gas that was not emitted and lost. The cost effectiveness values shown do not consider these savings. Note that the consideration of savings does not impact whether the cost effectiveness of any of these options falls within the ranges considered reasonable by the EPA.

[b] For overall cost effectiveness to be considered reasonable, either the cost effectiveness of methane or VOC on a single pollutant basis must be within the ranges considered reasonable by the EPA, or the cost effectiveness of both methane and VOC on a multipollutant basis must be within the ranges considered reasonable by the EPA.

[c] For multiple pump scenarios, an equal number of diaphragm and piston pumps is assumed.

While the costs for electric pumps and instrument air systems assume access to electrical power (that is, access to the grid), solar-powered pumps can be utilized at many remote sites that do not have access to electrical power. Instrument air systems can also be utilized at sites without access to the electricity grid but would require the installation and operation of a generator. These generators could be powered by engines fueled by solar energy, natural gas, or diesel. While such systems are technically a viable option at these remote sites, we did not have detailed cost information available to include these systems in our analysis. One commenter provided estimated costs ranging from $60,000 to over $200,000 for an instrument air system driven by a natural gas generator.[167] The commenter also provided an estimate of $250,000 for an instrument air system powered by solar energy. However, the focus of the comments and these cost estimates was pneumatic controllers, not pumps. The EPA is specifically requesting information on whether these costs are representative of systems that could be used to power compressed air-driven pneumatic pumps, as well as comments on whether a single generator or solar system could be used to power both pneumatic controllers and pneumatic pumps.

[167] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

Proposed BSER Conclusion. As demonstrated in the analysis, there are pneumatic pump options that do not use natural gas for which the cost effectiveness is within the ranges considered to be reasonable by the EPA. These types of pumps can be utilized at sites with access to grid electricity as well as at remote sites that do not have this access.

This BSER conclusion is consistent with the EPA's findings in 2021. However, at that time we were unable to conclude that pumps that do not use natural gas represented BSER due to our inability to conclude that technical limitations previously identified had been overcome. As summarized above, several commenters continue to maintain that there are significant technical limitations, particularly with solar-powered pneumatic pumps. However, other commenters provided evidence that pneumatic pumps not driven by natural gas are available and in use in the industry.

Under CAA Section 111(b), the EPA must determine that the BSER has been ''adequately demonstrated.'' The EPA concludes that pneumatic pump systems that do not use natural gas have met this standard at sites both with and without access to grid electricity. In addition, as discussed above, we have concluded that there are system options available at sites in all segments of the industry that have cost effective values considered reasonable by the EPA.

Secondary impacts from these non-natural gas-driven pumps, particularly from the use of instrument air systems, are indirect, variable, and dependent on the electrical supply used to power the compressor. The secondary impacts resulting from the increase in electricity needed from the grid to power compressors for instrument air were discussed above for pneumatic controllers. These also represent the impacts that would occur for compressors used to provide instrument air for pneumatic pumps. However, a single compression system, appropriately sized, could power both pneumatic controllers and pumps at a site, meaning that the electricity usage and resulting secondary impacts would not necessarily be doubled. No other secondary impacts are expected.

In light of the above, we find that the BSER for reducing methane and VOC emissions from natural gas-driven piston and diaphragm pumps at all segments of the industry is the use of pneumatic pumps that do not use natural gas as a driver. This option results in a 100 percent reduction of direct emissions for both methane and VOC, or zero methane and VOC emissions. Therefore, for NSPS OOOOb, we are proposing to require a natural gas emission rate of zero for all pneumatic pumps in the source category.

One request for comments that the EPA solicited in November 2021 was related to the potential subcategorization of pumps based on access to grid electrical power. Because we have determined that the requirement to use zero-emission pumps that are not powered by natural gas is BSER for all sites, regardless of whether the site has access to electrical power, we have decided that subcategorization is not necessary.

Technical Infeasibility Situations. While we conclude that zero-emission pneumatic pumps not powered by natural gas are adequately demonstrated as BSER, we understand that there may be specific conditions at sites without access to electricity that result in situations where it may be technically infeasible to utilize a non-natural gas-driven pump. Therefore, we also analyzed alternatives that could be incorporated into NSPS OOOOb in these instances. Note that because we have concluded that it should always be technically feasible for sites with access to electricity to utilize zero-emission pneumatic pumps that are not driven by natural gas, these alternatives would only be available at sites that do not have access to electricity.

First, we analyzed capturing the natural gas emissions from the pneumatic pump through venting and routing them to an existing process. The costs associated with this option are a capital cost of $6,102 with an annual cost of $869 (capital recovery using 7 percent interest for 10 years). The cost effectiveness for a single diaphragm pump in the production segment, assuming 100 percent capture, was $251 per ton of methane removed ($79 per ton with savings) and $903 per ton of VOC removed ($284 per ton with savings). On a multipollutant basis, these cost effectiveness values were $126 per ton of methane ($39 per ton with savings) and $452 per ton of VOC ($142 per ton with savings). For a single piston pump, the cost effectiveness was $2,286 per ton of methane removed ($2,114 with savings) and $8,224 per ton of VOC ($7,604 with savings). On a multipollutant basis, these cost effectiveness values were $1,143 per ton of methane ($1,057 per ton with savings) and $4,112 per ton of VOC ($3,802 per ton with savings).

For the representative site 3 (with one diaphragm piston and one piston pump), the single pollutant cost effectiveness values were $226 per ton of methane reduction ($54 with savings) and $814 per ton of VOC reduction ($194 with savings). The multipollutant cost effectiveness values were $113 per ton of methane reduction ($27 with savings) and $407 per ton of VOC reduction ($97 with savings).

All of these cost effectiveness values for both methane and VOC are within the ranges considered reasonable by the EPA, with the exception of the single pollutant cost effectiveness values for methane and VOC for a piston pump. However, since the multipollutant cost effectiveness of both methane and VOC were in the range considered acceptable by the EPA for a site with a single piston pump, we determined that this is an acceptable option.

For the transmission and storage segment, the cost effectiveness for a single diaphragm pump was $192 per ton of methane removed and $40,640 per ton of VOC. On a multipollutant basis, these cost effectiveness values were $96 per ton of methane and $20,320 per ton of VOC. For a single piston pump, the cost effectiveness was $1,750 per ton of methane removed and $26,095 per ton of VOC. On a multipollutant basis, these cost effectiveness values were $875 per ton of methane and $13,048 per ton of VOC. For the representative site with one diaphragm piston and one piston pump, the single pollutant cost effective values were $173 per ton of methane reduction and $11,708 per ton of VOC reduction, and the multipollutant cost effectiveness values were $87 per ton of methane reduction and $5,854 per ton of VOC reduction.

All of the cost effectiveness values for methane on a single pollutant basis are within the ranges considered reasonable by the EPA. In addition, the multipollutant cost effectiveness for both methane and VOC were in the ranges considered reasonable by the EPA for a site with one diaphragm and one piston pump.

In conclusion, because we believe that routing to a process is a viable and cost-effective option for pneumatic pumps when it is technically infeasible to use a zero-emission pneumatic pump not driven by natural gas, this option is included in the proposed NSPS OOOOb. In order to utilize this option, an owner or operator must demonstrate technical infeasibility. In addition, because the CVS system that collects and routes these emissions to a process could develop leaks, the proposed NSPS OOOOb requires compliance with the CVS no-detectable leaks requirements specified in 40 CFR 60.5411b(a) and (c) of the proposed regulatory text.

The EPA is interested in several aspects related to the option of collecting the pneumatic pump emissions and routing them to a process. First, we are soliciting information that describes specific situations where owners and operators have utilized this option to use, rather than lose, the valuable natural gas emitted from pneumatic pumps. We are interested in gathering information on the specific processes and types of equipment that are needed to do so, as well as information on the related costs. We are also interested in information to support our understanding that routing to a process achieves a 100 percent reduction in emissions. This understanding is based on the fact that the gas that is emitted from pneumatic pumps is drawn directly from the raw product gas stream that will be collected and routed to a gathering and boosting station and eventually to a natural gas processing plant (*i.e.,* the gas ''sales line''). Therefore, the emissions from the pneumatic pumps are of the same composition as the gas in the sales line. Since the emissions are at atmospheric pressure, it is likely that the gas would need to be compressed prior to re-introduction to the sales line. We do not expect that this compression would result in emissions. Similarly, since the composition of these emissions is typically high in methane, the heat content would make it amendable to being used as fuel, or introduced with the primary fuel stream for use in an engine without the need for additional processing that could result in emissions.

This request for information includes information on the installation of VRUs. Note that the analysis above did not include the installation of a new VRU. As discussed in section IV.D.1.b.iii for pneumatic controllers, we do not believe that a VRU would be needed to enable the use of the emissions from pneumatic pumps (in contrast to emissions from storage vessels and centrifugal compressor wet seal fluid degassing systems). Despite this belief, in the analysis for the November 2021 proposal, we did analyze the costs to install a new VRU to process the emissions from pneumatic pumps to enable the routing to a process. We determined that these costs were unreasonable, given the emission reductions. One commenter felt that our VRU costs were inflated. We are interested in learning about situations where a VRU would be needed to enable the use of emissions from a pneumatic pump in a process, as well as the costs of those VRUs.[168] These costs are included in the November 2021 TSD.

We also recognize that there could be situations at sites without access to electricity where not only is it technically infeasible to utilize zero-emission pneumatic pumps that are not driven by natural gas, but it is also technically infeasible to route the emissions to a process. Therefore, we also considered the option to route to a control device. The analysis conducted for the November 2021 proposal concluded that while it was reasonable to route the emissions from a pneumatic pump to an existing control device, the cost effectiveness of installing a new control device dedicated to the pneumatic pump was higher than the EPA considers reasonable. This finding is still valid for this proposal for sites with a single pneumatic pump. However, as noted above, the EPA changed the pneumatic pump affected facility definition for this proposal to be the collection of natural gas pneumatic pumps at a site. Therefore, we updated the analysis to consider the cost effectiveness of installation of a new control device that would control emissions from multiple natural gas-driven pneumatic pumps.

This analysis found that where there are four or more natural gas-driven pneumatic diaphragm pumps at a site, the cost effectiveness of a new combustion device that reduces emissions by 95 percent from all the pumps is within the ranges considered reasonable by the EPA. For the production segment, the cost effectiveness values for a site with four diaphragm pumps are $1,869 per ton of methane reduced and $6,723 per ton of VOC reduced on a single pollutant basis. On a multipollutant basis, these values are $934 per ton of methane and $3,361 per ton of VOC. Therefore, these cost effectiveness values are considered reasonable for methane on a single pollutant basis as well as on a multipollutant basis. For the transmission and storage segment, the single pollutant methane cost effectiveness was $1,430, which is in the range considered reasonable by the EPA.

Therefore, the proposed NSPS OOOOb includes the requirement for production and transmission and storage sites as follows: if an owner or operator demonstrates that it is technically infeasible to install zero-emission non-natural gas-driven pumps, and it is technically infeasible to route to a process, the emissions must be routed to a control device to achieve 95 percent reduction of the methane and VOC if the pneumatic pump affected facility includes four or more diaphragm pumps. Note that emissions from all piston pumps at the site would also be required to be reduced by 95 percent. For pneumatic pump affected facilities with less than four diaphragm pumps, where it has been demonstrated that it is technically infeasible to use zero-emission non-natural gas-driven pumps and infeasible to route to a process, the proposed NSPS OOOOb mirrors the November 2021 proposal. That is, the pneumatic pump emissions must be routed to an existing control device (if one is available) to achieve 95 percent reduction.

There are several instances in this hierarchical structure of the proposed NSPS OOOOb where less stringent requirements may apply if it is determined that the more stringent requirement is technically infeasible. The proposed rule requires that these demonstrations be made by a qualified professional engineer or an in-house engineer with relevant expertise. While several commenters stressed that in-house engineers should be allowed to make required certifications and determinations, other commenters expressed concerns that only certified professional engineers should be allowed to certify technical infeasibility. The EPA concluded that the flexibility to allow in-house engineers to make these determinations and certifications is warranted, especially given the potential shortage of professional engineers with specific expertise required for these determinations (that is, expertise in solar-powered pneumatic pumps or routing pneumatic pump emissions to a process).

However, the EPA is also committed to ensuring that this technical infeasibility provision is not abused or used as a loophole to avoid implementing important pollution reduction measures. The EPA stresses that each technical infeasibility determination must be documented, and the following statement submitted to the EPA (or delegated enforcement authority): ''I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted, and this report was prepared, pursuant to the requirements of 40 CFR 60.5393b(c)(1). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.'' The EPA wants to make it clear that in the case that such a certification is determined by the Agency to be fraudulent, or significantly flawed, not only will the owner or operator of the affected facility be in violation of the standards, but the person that makes the certification will also be subject to civil and potentially criminal penalties.

c. Summary of Proposed NSPS OOOOb

The proposed NSPS OOOOb defines a pneumatic pump affected facility as the collection of natural gas-driven diaphragm and piston pneumatic pumps at all types of sites throughout the production, processing, and transmission and storage segments of the source category. Specifically, these sites include well sites, centralized production facilities, onshore natural gas processing plants, and compressor stations. Pneumatic pumps that are not driven by natural gas are not included

[168] See Document ID No. EPA–HQ–OAR–2021–0317–0844.

in the proposed pneumatic pump affected facility as long as records are maintained to verify that non-natural gas-driven pumps are used.

Natural gas-driven pumps that are in operation less than 90 days per calendar year are not part of an affected facility provided that the owner or operator keeps records of the days of operation each calendar year and submits such records to the EPA (or delegated enforcement authority) upon request. Any period of operation during a calendar day counts toward the 90-calendar day threshold.

In addition to the modification definition in 40 CFR 60.14 and the reconstruction definition in 40 CFR 60.15, the proposed rule includes clarification of these terms for the pneumatic pump affected facility. A modification occurs when the number of natural gas-driven pneumatic pumps at a site is increased by one or more, and reconstruction occurs when either the cost of the pumps being replaced exceeds 50 percent of the cost to replace all the pumps, or when 50 percent or more of the pneumatic pumps at a site are replaced.

The proposed BSER is the use of pneumatic pumps not powered by natural gas; the proposed standard of performance is zero emissions of methane and VOC. As noted above, compliance with this standard effectively eliminates the existence of a pneumatic pump affected facility (which is a natural gas-driven pump or collection of pumps, by definition). For sites in the production or transmission and storage segment of the industry who do not have access to electricity, the proposed standards include a hierarchical structure that allows the use of natural gas-driven pneumatic pumps based on the technical feasibility of pneumatic pump control measures. This hierarchy is not available to natural gas processing plants, as the only proposed requirement is the use of non-natural gas-driven pneumatic pumps at these sites.

If it is demonstrated that it is technically infeasible to utilize a pneumatic pump not driven by natural gas at a site in the production or transmission and storage segment of the industry which does not have access to electricity, compliance may be achieved by collecting methane and VOC emissions from all pumps (diaphragm and piston pumps) in the affected facility via a CVS and routed to a process, which we understand results in 100 percent emissions reductions. The CVS is required to comply with the CVS requirements specified in 40 CFR 60.5411b(a) and (c) of the proposed regulatory text, which includes certification by a professional or in-house engineer that the CVS was designed properly and was operated in accordance with the no detectable emissions provisions. For this ''tier one'' technical infeasibility determination, a demonstration must be made that using a solar-powered electric pneumatic pump is not technically feasible. This demonstration must be certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of solar-powered pneumatic pumps. Alternatively, this demonstration can be certified by a solar-powered pneumatic pump manufacturer that has successfully installed solar-powered pneumatic pumps at other oil and natural gas sites. In addition, the tier one technical infeasibility demonstration must prove that it is not technically feasible to install a compressed air system powered by either a natural gas-driven generator or a solar-powered generator. This demonstration must include, but not be limited to, the ability to operate a generator, including access to natural gas; access to solar power; or the inability of a compressed air system to power the pneumatic pump. This demonstration must be certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of natural gas-driven or solar-powered generators to power pneumatic pumps. In addition to the records associated with the technical infeasibility determination/certification, a record of the certification of the design of the CVS must be maintained, along with records of all inspections required to demonstrate compliance with the no detectable emissions requirements.

If it is demonstrated that it is technically infeasible to collect the emissions from all pneumatic pumps in the affected facility and route them to a process (in addition to the demonstration that it is infeasible to utilize a pneumatic pump not driven by natural gas), compliance may be achieved by collecting methane and VOC emissions from all pumps (diaphragm and piston pumps) in the affected facility via a CVS and routing them to a control device that achieves 95 percent reduction in methane and VOC emissions. The CVS would be subject to the design requirements, specified in 40 CFR 60.5411b(a) and (c) of the proposed regulatory text, and must comply with the no detectable emissions requirements. The control device would be subject to testing and continuous monitoring requirements. This ''tier two'' demonstration must include, but is not limited to, safety considerations, distance from a process, pressure losses and differentials which impact the ability of the process to handle all the pneumatic pump affected facility emissions routed to it, or other technical reasons the process cannot handle all the pneumatic pump affected facility emissions routed to it. This demonstration must be certified by either a qualified professional engineer or an in-house engineer with expertise on the design and operation of the pneumatic pump affected facility and the process to which emissions will be routed. A demonstration of technical infeasibility may not be based on the infeasibility of the design and operation of CVS to collect emissions from all the pneumatic pumps in the affected facility. In addition to the records associated with both technical infeasibility determinations and certifications, a record of the certification of the design of the CVS must be maintained, along with records of all inspections required to demonstrate compliance with the no detectable emissions requirements. Records must also be maintained of either the performance testing of the control device (whether at the site or by the manufacturer), or records demonstrating compliance with 40 CFR 60.18 General Provisions flare requirements. Finally, monitoring records must be maintained to demonstrate that the control device is operating properly on a continuous basis.

''Tier three'' of the hierarchy applies if there are less than four natural gas-driven diaphragm pumps at a site. In this situation, the owner or operator is not required to install a new control device. The proposed standard for the pneumatic pump affected facilities at sites with less than four diaphragm pumps mirror those proposed in the November 2021 proposal, which require that methane and VOC emissions be reduced by 95 percent by routing to an existing control device if: (1) A control device is onsite, (2) the control device can achieve a 95 percent reduction, and (3) it is technically feasible to route the emissions to the control device. However, the proposed rule would exempt an owner or operator from this requirement provided that they document the technical infeasibility of routing the emissions to an existing control device and submit it in an annual report. Similarly, where it is feasible to route the emissions to a control device, but the control cannot achieve 95 percent reduction, the proposed rule would exempt the owner or operator from the 95 percent reduction requirement, provided that the owner or operator maintain records demonstrating the percentage reduction that the control device is designed to achieve.

The EPA notes that inherent throughout these proposed pneumatic pump requirements are demonstrations of technical infeasibility. Each technical infeasibility determination must include a certification, signed and dated by the qualified professional engineer or in-house engineer. The EPA wants to make it clear that in the case that such a certification is determined by the Agency to be fraudulent, or significantly flawed, not only will the owner or operator of the affected facility be in violation of the standards, but the person that makes the certification will also be subject to civil and potentially criminal penalties.

2. EG OOOOc

The proposed presumptive standards for methane emissions from existing pneumatic pumps mirror those described above for NSPS OOOOb. The EPA did not identify any circumstances that would result in a different BSER for existing sources under the EG OOOOc.

In light of the proposal to require zero-emission pneumatic pumps not powered by natural gas for both new and existing sources, the EPA would like to highlight comments and solicit related information. Commenters on the November 2021 proposal indicated that the proposed rules would exacerbate demand, increase costs, and increase pressure on the supply chain for zero-emissions systems. One commenter stated that reliability and availability of alternate zero-emission options (*i.e.,* solar-powered/battery backup systems, and electric, self-contained systems) are a major concern for safe and reliable operations.[169] Another commenter indicated that one of their members contacted a vendor within the last six months to find out how much deployment there has been of solar systems and electric controllers.[170] The commenter reported that the vendor indicated that in the past 10 years, they have conducted 200 retrofits and 300 new installs, and the vendor estimates that it can only service approximately 200 installs per year. Additionally, the commenter indicated that operators are already experiencing 6 to 12-month lead times for delivery of solar packages. So that it may continue to gather information on this subject, the EPA is specifically requesting comment on the availability of pneumatic pump systems not powered by natural gas.

F. Wells and Associated Operations

1. Affected and Designated Facility Definitions

a. NSPS OOOOb

The November 2021 proposal had three separate affected facilities associated with oil and natural gas wells. These included: (1) The well completion affected facility, defined as a single well that conducts a well completion operation following hydraulic fracturing or refracturing; (2) the associated gas affected facility, defined as any oil well that produces associated gas; and (3) the well liquids unloading affected facility, with two proposed options for the definition. Under Option 1, a well liquids unloading affected facility was defined as every well that undergoes liquids unloading. Under Option 2, a well liquids unloading affected facility was defined as every well that undergoes liquids unloading using a method that is not designed to completely eliminate venting. Each of these three types of affected facilities included proposed definitions of what would constitute a modification to an oil and natural gas well. The result of including all three definitions would have been that a single well could have been three different affected facilities for three different emissions sources. In addition, a single well could have been a new source affected facility under NSPS OOOOb and a designated facility under EG OOOOc.

To eliminate the potential confusion from this complex regulatory structure, the EPA is proposing to change its approach as part of this proposed action. Rather than three separate well affected facilities, we are now proposing a definition of well affected facility, which is defined as a single well, in the proposed NSPS OOOOb. A well is defined as a hole drilled for the purpose of producing oil or natural gas. More discussion of the rationale for this revision specific to each of the three well operations is provided in sections IV.E.2, 3, and 4 below.

There are separate proposed standards for well completions, associated gas from oil wells, and gas well liquids unloading operations, all or some of which could apply to a well affected facility. These proposed standards and their applicability are discussed in more detail in sections IV.E.2, 3, and 4 of this preamble. A well affected facility is only required to comply with the standards that are applicable to the well. For example, a gas well would not be subject to the oil well with associated gas standards. The proposed NSPS OOOOb specifies that a modification to an existing well occurs when the definition of modification in 40 CFR 60.14 is met, including when an existing well undergoes hydraulic fracturing or re-fracturing.

b. EG OOOOc

The November 2021 proposal only included the oil wells with associated gas designated facility, as the proposed definition of modification for the NSPS OOOOb well liquids unloading affected facility would have resulted in all wells that performed liquids unloading being new or modified sources. As discussed above and in section IV.E.3, the EPA has not retained the proposed well liquids unloading modification definition in this supplemental proposal. Therefore, this proposal includes standards for gas well liquids unloading at designated facilities in the proposed EG OOOOc. However, since the fracturing or re-fracturing of an existing well would constitute a modification under NSPS OOOOb, which makes the well a well affected facility under NSPS OOOOb, there would never be an existing well subject to completion requirements.

The well designated facility definition in EG OOOOc is now proposed to be defined as a single well and EG OOOOc would include presumptive standards for associated gas from oil wells and gas well liquids unloading.

2. Associated Gas From Oil Wells

a. NSPS OOOOb

i. November 2021 Proposal

Associated gas originates at wellheads that also produce hydrocarbon liquids and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon phase by separation. In the November 2021 proposal, the EPA proposed standards in NSPS OOOOb to reduce methane and VOC emissions resulting from the venting of associated gas from oil wells. Specifically, the November 2021 proposal would have required owners and operators of oil wells to route associated gas to a sales line. If access to a sales line was not available, the EPA proposed that the gas could have been used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction of methane and VOC

[169] See Document ID No. EPA–HQ–OAR–2021–0317–0739.

[170] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

emissions.[171] The EPA also requested comment on whether to include re-injecting associated gas for enhanced oil recovery or another purpose should be included in the list of beneficial uses. The following sections provide discussions of the comments submitted on the November 2021 proposal, the changes resulting from these comments, and our rationale for the changes. Section IV.E.2.iii summarizes the resulting proposed requirements included in this supplemental proposal.

ii. Changes From November 2021 Proposal

The BSER determination for associated gas from oil wells was discussed in section XII.J.1.e of the November 2021 proposal (86 FR 63237–63238; November 15, 2021). The EPA did not receive any comments on the proposal that resulted in a change to the analysis that had concluded that BSER for associated gas from oil wells was the routing of the associated gas to a sales line.

In this action, we are proposing changes to the associated gas from the oil wells affected facility definition, the hierarchy of the standard, and the compliance options. In addition to proposed changes associated with these topics, a significant addition to the proposed rule is the establishment of requirements for situations when associated gas from an oil well that is primarily either routed to a sales line or used for another beneficial purpose is unable to utilize the gas in that manner due to gathering system or other disruptions. In addition, the EPA is soliciting additional information on potential emerging technologies that provide uses for the associated gas in a beneficial manner other than routing to a sales line, using as a fuel, or reinjecting the gas. Examples of such emerging technologies provided by commenters include methane pyrolysis[172] and condensing the gas and transporting it to other sites for use.[173]

Hierarchy of the Standard and Control Options. As discussed in section IV.E.1.b.i, the standard for associated gas from oil wells in the November 2021 proposal was to route the associated gas to a sales line. If access to a sales line was not available, the proposal allowed the gas to be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions.

The EPA specifically solicited comment on how ''access to a sales line'' should be defined. Several commenters[174] stated that access to a sales pipeline is based on numerous criteria that can be outside a well operator's control. They indicated that, in most cases, the midstream company that designs, builds, and operates the gas gathering system (sales line) and gas processing plant is not the same as the well owner and operator, landowner, and mineral lease owner. Thus, commenters concluded that ''access to a sales line'' does not equate to availability to route gas into that sales line.

Commenters also objected to the overall construct of the proposal where the standard required the routing to a sales line in situations where access to sales line was available. They indicated that using the gas as an onsite fuel source should be an option that was allowed on an equal basis with routing to a sales line.

The EPA agrees with these commenters regarding the associated gas from oil wells standards. First, the EPA understands that the sales line is typically not under the control of the well owner, and that the gathering system owner dictates when gas can be routed to a sales line. We believe this understanding supports allowing other uses of associated gas, which also avoid methane and VOC emissions from venting or flaring of associated gas, as acceptable compliance options. Specifically, while BSER was determined to be routing to a sales line, we agree that beneficial uses of the associated gas should be allowed as these options are equivalent in terms of emission reduction to the identified BSER. Therefore, we are proposing to expand what is considered beneficial use to include options beyond routing to the sales line. This proposed rule would require any of the following options for beneficial use: (1) Routing associated gas from oil wells to a sales line; (2) using the associated gas as a fuel or for another useful purpose that a purchased fuel or raw material would serve; (3) or reinjecting the associated gas into the well or injecting the associated into another well for enhanced oil recovery.

Regarding re-injection, commenters indicated that re-injection should be included as one of the options allowed. One commenter stated that well operators may prefer to reinject associated gas. They pointed out that reinjection is used widely in Alaska, where 90 percent of associated gas is injected into oil-bearing formations. They concluded that reinjection as a method of gas capture has significant emissions reduction benefits, because it largely eliminates emissions of methane and other pollutants.[175]

As noted above, commenters also mentioned examples of emerging techniques that provide additional beneficial uses of the associated gas, including compressing the gas and transporting it to a nearby processing plant or pipeline and methane pyrolysis. The EPA interprets the third criterion, ''used for another useful purpose,'' to include these emerging techniques but is soliciting comment whether an additional criterion should be added to make this clear. The EPA is also soliciting comment on more specific technologies that have been proven to be viable in the field to utilize associated gas and avoid venting or flaring.

Some commenters stated that the proposed rule would not succeed in ensuring that oil and gas operators will not flare associated gas in situations where other options were available, and these commenters opposed routine flaring as a compliance alternative on par with the non-sales line ''beneficial'' use options. They urged the EPA to abandon what they described as an ''unworkable framing,'' and instead suggested that the EPA adopt a BSER that would eliminate routine flaring except in specific and narrowly defined circumstances. We agree that flaring of the gas should only be allowed in situations where it is not feasible to route the associated gas to a sales line or use it for one of the other useful purposes described above. Therefore, this proposed rule would allow flaring of the associated gas only if the owner or operator certifies that it is not feasible to route the associated gas to a sales line or use it for another beneficial purpose due to technical or safety reasons. This demonstration would need to address the specifics regarding the lack of availability to a sales line, including efforts by operators to get access to a sales line or to facilitate alternative off-site transport and use of associated gas. The demonstration would also need to demonstrate why all potential beneficial

[171] The EPA solicited comment on whether to also include re-injecting associated gas as an alternative (86 FR 63237; November 15, 2021) and based on comments in support of this option [EPA–HQ–OAR–2021–0317–0844], is including such alternative in this supplemental proposal.

[172] See Document ID No. EPA–HQ–OAR–2021–0317–0594.

[173] See Document ID No. EPA–HQ–OAR–2021–0317–0558.

[174] See Document ID Nos. EPA–HQ–OAR–2021–0317–0793, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0911.

[175] See Document ID No. EPA–HQ–OAR–2021–0317–0844.

uses (including emerging techniques) are not feasible due to technical or safety reasons. The first demonstration would require certification by a professional engineer or other qualified individual and would be submitted in the first annual report for the well affected facility. In each subsequent annual report, the owner or operator would be required to report whether any circumstances had changed regarding the need to flare relative to the initial certification, and if so, which beneficial use would be applied to the associated gas.

The EPA recognizes that several states have adopted standards to further reduce routine flaring of associated gas, including Colorado and New Mexico. As noted above, several commenters also urged the EPA to take additional steps to eliminate routine flaring of associated gas, except in very limited cases such as emergencies or for safety reasons. Therefore, the EPA is taking comment on steps the Agency should consider taking to disallow the indefinite continuation of routine flaring. First, the EPA is taking comment on whether the ongoing annual requirement to report whether circumstances had changed regarding the need to flare should result in a need to perform a more thorough analysis and engineering certification comparable to the initial certification required once an owner or operator becomes subject to the rule. For example, it may be appropriate to require an owner or operator to provide an additional engineering certification that flaring is the only option where a new gathering pipeline is installed within a certain distance of an oil well. Second, the EPA is taking comment on whether it would be appropriate to require more rigorous consideration of alternatives to flaring after a set threshold is reached (*e.g.,* after a set time of flaring (such as 2 years) or after a set volume of gas has been flared). Third, the EPA requests comment on whether there are any provisions in existing state regulations beyond what is already included in this supplemental proposal, or other measures (such as minimum capture requirements or volumetric limits on flaring), that the EPA should consider in its BSER analysis. Finally, the EPA is also soliciting comment on whether there are specific emerging technologies that should be required to be addressed in this demonstration and listed in the rule.

Requirements when Gathering System or Other Disruption Occurs. The EPA is aware that when associated gas is typically routed to a sales line there could be situations that arise that can cause an interruption of the ability to route the gas to the sales line. As discussed above and pointed out by commenters, this situation is usually not under the control of the owner or operator of the well. The EPA agrees that interruptions where the gathering system owner is suddenly unable to accept the associated gas from the well could also occur that impact the ability to utilize the associated gas as a fuel or for another useful purpose. The EPA has considered options for this situation for this supplemental proposal. One option considered was that this situation would constitute a deviation or violation of the standard unless the owner or operator elected to shut the well in and halt the production of the associated gas. The EPA did not select this option in this supplemental proposal. The EPA concluded that such situations could constitute a technical or safety reason that could be used to justify the use of a control device that achieves 95 percent reduction of methane and VOC emissions. Therefore, the EPA is proposing to require that if owners and operators anticipate that there may be interruptions in the ability to route the associated gas to a sales line or to use it for another beneficial purpose, they must provide a technical or safety demonstration in their annual report and install and operate a control device that achieves the required reduction during these temporary periods. It is anticipated this control device would need to be permanently installed to account for these periods when associated gas could not be routed to a sales line or used for other beneficial purposes, but the EPA is soliciting comment on whether the use of temporary controls could also serve this purpose. Further the EPA is soliciting comment on what additional requirements would be necessary to ensure a temporary control device is onsite and operational to immediately control emissions when necessary for these circumstances. Venting of the associated gas under any circumstances would represent a violation of the proposed standards, even if for a short period.

Potential Exemptions and Alternative BSER for Unique Circumstances. Several commenters on the November 2021 proposal identified situations where it would not only be infeasible to route the associated gas to a sales line or use it for another beneficial purpose, but where it would also be infeasible to route it to a flare or other control device to achieve 95 percent reduction in methane and VOC emissions. Examples of these situations include when the flow rate, pressure, or volume of the associated gas is insufficient to route to a sales line or to support the continuous operation of a flare or combustion device; when the composition of the gas is such that it cannot be routed to a sales line or used in some manner (*e.g.,* 97 percent CO_2 and 3 percent methane) and it does not contain sufficient heat content to combust without the addition of unreasonable amounts of propane; wildcat wells; and delineation wells. One commenter provided detailed information about the issues with certain wells in Wyoming,[176] The EPA believes that these situations could warrant an exemption or an alternative standard. However, this proposed rule does not include any exemptions or allowances for these situations due to lack of specific sufficient information. Therefore, the EPA is interested in additional information on gas compositions of associated gas that would make it both unusable for a beneficial purpose and unable to be flared. The EPA is not only interested in why commenters feel these situations warrant an exemption from the associated gas standards as proposed, but also what methods are currently in use, or could be used, to minimize methane and VOC emissions in these situations.

iii. Summary of Proposed Standards

In summary, this supplemental proposal allows owners and operators four compliance options to reduce or eliminate emissions of methane and VOC from associated gas from oil wells. These options are: (1) Recover the associated gas from the separator and route the recovered gas into a gas gathering flow line or collection system to a sales line, (2) recover the associated gas from the separator and use the recovered gas as an onsite fuel source, (3) recover the associated gas from the separator and use the recovered gas for another useful purpose that a purchased fuel or raw material would serve, or (4) recover the associated gas from the separator and reinject the recovered gas into the well or inject the recovered gas into another well for enhanced oil recovery.

Associated gas cannot be routed to a flare or other combustion device unless the owner or operator demonstrates that all four options discussed above are infeasible due to technical or safety reasons, and that demonstration is approved by a certified professional engineer. Any combustion device must meet the requirements in 40 CFR

[176] See Document ID No. EPA–HQ–OAR–2021–0317–0955.

60.5412b and that monitoring, recordkeeping, and reporting be conducted to ensure that the combustion device is constantly achieving the required 95 percent reduction. More information on the control device monitoring and compliance provisions is provided in section IV.H of this preamble.

In each annual report, owners and operators would be required to identify each well affected facility with associated gas that was constructed, modified, or reconstructed during the reporting period. The report would specify whether the associated gas will be routed into a gas gathering flow line or collection system to a sales line, used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, reinjected into the well, or injected into another well for enhanced oil recovery. If making a demonstration that it is infeasible to utilize one of these options due to technical or safety reasons, this demonstration would also be included in the first annual report. This demonstration would clearly and comprehensively justify why all of these options are infeasible, including all emerging technologies that could represent a beneficial use of the gas. This demonstration would be required in situations where the associated gas is always routed to a control device, as well as for situations where disruptions or interruptions result in the need to route the associated gas to a control device for temporary periods.

In subsequent annual reports, owners and operators complying by routing the associated gas to a gas gathering flow line or collection system to a sales line, used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, reinjected into the well, or injected into another well for enhanced oil recovery would be required to report all instances when associated gas was vented to the atmosphere. Owners and operators complying by routing the associated gas to a control device and achieving 95 percent reduction in methane and VOC would be required to report all instances when associated gas was vented to the atmosphere. In addition, these owners and operators would be required to report any changes made at the site since the original technical infeasibility demonstration and whether the change impacted the feasibility to route the associated gas to a gas gathering flow line or collection system to a sales line, use the gas as an onsite fuel source, use the gas for another useful purpose that a purchased fuel or raw material would serve, reinject the gas into the well, or inject the gas into another well for enhanced oil recovery. If the change did not impact this feasibility, a revised demonstration and certification would be required. If the change did impact the feasibility, the owner or operator would need to report the new method of compliance that is utilized.

Required records would include documentation of the specific type of compliance method (*i.e.,* routed into a gas gathering flow line or collection system to a sales line, used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, injected into another well for enhanced oil recovery) was used. Owners and operators would also be required to maintain records that demonstrate why the required capture and use requirements are not feasible and why the use of a control device is the only option. If the control device is only used on a temporary basis when disruptions or interruptions occur in the primary compliance method for the associated gas, the owner or operator would document the periods that the gas is routed to the control device. All records associated that demonstrate proper design and operation of the control device would also be required to be maintained (see section IV.G of this preamble). Finally, all instances where emissions are vented would be recorded, along with records of actions that were taken during these periods to minimize emissions to the atmosphere.

b. EG OOOOc

The proposed presumptive standards for associated gas from existing oil wells mirror those described above for NSPS OOOOb. The EPA did not identify any circumstances that would result in a different BSER for existing sources under the EG OOOOc.

3. Gas Well Liquids Unloading Operations

a. NSPS OOOOb

i. November 2021 Proposal

In the November 2021 proposal, the EPA proposed to add standards to reduce VOC and methane emissions from each new, modified, or reconstructed gas well that conducts a well liquids unloading operation in NSPS OOOOb. In that proposal, the EPA proposed a standard that would require owners or operators to perform well liquids unloading with zero methane or VOC emissions. In the event that it is technically infeasible or not safe to perform well liquids unloading with zero emissions, the EPA proposed to require owners and operators to establish and employ BMPs to minimize methane and VOC emissions during well liquids unloading operations to the extent possible. Two regulatory approaches were co-proposed in the November 2021 proposal. The first approach defined the affected facility as every well that undergoes liquids unloading, while the second approach defined the affected facility as every well that undergoes liquids unloading using a method that is not designed to completely eliminate venting. Both approaches require zero emissions unless technically infeasible, and where infeasible, both approaches require minimizing venting using BMPs.

ii. Changes From November 2021 Proposal

As described in section IV.E.1, the EPA is proposing to define the ‘‘affected facility’’ as a single well in this supplemental proposal, instead of defining it as a well that undergoes liquids unloading. Further, the EPA is revising the ‘‘modification’’ definition to apply to a single well that undergoes hydraulic fracturing or refracturing. This revised definition replaces the definition proposed in the November 2021 proposal, where all well liquids unloading events would have been considered a modification.

Several commenters stated that the November 2021 proposal's definition of modification for well liquids unloading operations was flawed in a number of respects. First, commenters asserted that not all well liquids unloading operations result in an increase in emissions to the atmosphere because some operations do not vent gas and therefore have zero emissions. We agree with commenters on this point; therefore, we are not maintaining the proposed definition that every well liquids unloading operation is a modification. Second, commenters stated that well liquids unloading operations are a part of the normal operation of the well and do not result in a physical or operational change to the well, and therefore do not meet the definition of modification in 40 CFR 60.2. The EPA agrees with the commenters that well liquids unloading operations are not physical changes to the well itself. A well liquids unloading operation does not change the shape, size, or any other physical feature of the well (*i.e.,* the hole drilled for the purpose of producing oil or natural gas).

The question of whether well liquids unloading operations constitutes an operational change to the well is more nuanced. The EPA understands that every gas well will eventually need to have liquids removed in order to improve or maintain production. While the definition of modification in this proposal has been adjusted to reflect the information commenters have provided, the EPA has yet to reach a conclusion on whether certain types of liquids unloading events could be an operational change to a well. The EPA is therefore requesting comment on operational scenarios where a well liquids unloading event could constitute a modification. Operational scenarios that may be considered a modification regarding well liquids unloading could include: (1) The first time, in the life of the well, that well liquids unloading occurs, (2) the first time, after fracturing or refracturing a well, that well liquids unloading occurs, (3) a change in the type or method of well liquids unloading, or (4) ongoing liquids unloading as part of a regular operational schedule. The EPA is requesting specific comment on whether these operational scenarios, or any additional ones, may or may not constitute a modification.

iii. Summary of Proposed Requirements

In this supplemental proposal, the EPA has provided regulatory text similar to the November 2021 co-proposed option 1, where all gas well liquids unloading operations would be subject to the regulatory requirements. The EPA is proposing the same standard of performance as discussed in the November 2021 proposal: perform well liquids unloading with zero methane or VOC emissions. The BSER is to employ techniques or technologies that eliminate methane and VOC emissions. Where it is technically infeasible or not safe to meet the zero emissions standard, employ BMPs to minimize methane and VOC emissions during well liquids unloading operations to the maximum extent possible. While we received multiple comments recommending regulating only well liquids unloading events that result in vented emissions, we are not including proposed regulatory text for the co-proposed option 2. Should the EPA decide to finalize the standards as stated in the November 2021 co-proposed option 2, the regulatory text specific to BMPs would remain relevant and is already provided in this supplemental proposal. As stated above, there are malfunctions that can result in vented emissions from well liquids unloading operations that would otherwise meet the zero emissions standard. Further, since each well liquids unloading operation is conducted based on the site-specific circumstances at the time the operation is planned, the EPA is concerned that a well might fluctuate between falling within and out of the scope of the standards if the standards only applied to well liquids unloading operations that result in vented emissions. Therefore, for ease of implementation to the owner or operator, the EPA is proposing to apply the proposed standards to all well liquids unloading operations regardless of if the operation results in vented emissions. The EPA is, however, specifically requesting further comment and any additional information regarding co-proposed option 2, where standards only apply to wells with well liquids unloading operations that result in vented emissions.

The EPA is also proposing specific recordkeeping and reporting requirements related to well liquids unloading operations. Wells that utilize a non-venting method would have reporting and recordkeeping requirements that would include records of the number of well liquids unloading operations that occur within the reporting period and the method(s) used for each well liquids unloading operation. A summary of this information would also be required to be reported in the annual report. The EPA also recognizes that under some circumstances, venting could occur when a selected liquids unloading method that is designed to not vent to the atmosphere is not properly applied (*e.g.,* a technology malfunction or operator error). Under this proposed rule, owners and operators in this situation would be required to record and report these instances, as well as document and report the length of venting and what actions were taken to minimize venting to the maximum extent possible.

Additionally, for wells that utilize methods that vent to the atmosphere, the proposed rule would require: (1) Documentation explaining why it is infeasible to utilize a non-venting method due to technical, safety, or economic reasons; (2) development of BMPs that ensure that emissions during liquids unloading are minimized; (3) employment of the BMPs during each well liquids unloading operation and maintenance of records demonstrating that the BMPs were followed; (4) reporting in the annual report both the number of well liquids unloading operations and any instances where the well liquids unloading operations did not follow the BMPs.

b. EG OOOOc

Since the November 2021 proposal considered all well liquids unloading events to be a modification, the EPA did not propose a designated facility definition or presumptive standards for well liquids unloading in the EG OOOOc. With the revisions to the affected facility definition and what activities constitute a modification, the EPA is now proposing to define a designated facility as a single well, like in the revised proposal for NSPS OOOOb. Further, the EPA is proposing presumptive standards for existing wells that conduct well liquids unloading operations in EG OOOOc that are the same as the standards proposed in NSPS OOOOb. Because the proposed standards provide flexibility for owners and operators to make site-specific decisions about what well liquids unloading operations to employ, the EPA did not identify any circumstances that would result in a different BSER for existing sources under EG OOOOc.

4. Well Completions

a. NSPS OOOOb

The EPA proposed to retain the requirements found in NSPS OOOO and NSPS OOOOa for reducing methane and VOC emissions through reduced emission completion (REC) and completion combustion in the November 2021 proposal. These standards would apply to well completions of hydraulically fractured or refractured oil and natural gas wells. The EPA is not proposing changes to the standards in this supplemental proposal, and the proposed regulatory text at 40 CFR 60.5375b reflects the standards of performance as proposed in the November 2021 proposal.

The proposed regulatory text included in this supplemental proposal is similar to the regulatory text found in 40 CFR 60.5375a for NSPS OOOOa. While the regulatory text is similar, the EPA has been made aware of potential confusion related to the well completion requirements and well completion recordkeeping requirements for wildcat wells, delineation wells, and low-pressure wells. Therefore, the proposed regulatory text for NSPS OOOOb includes language to clarify these particular standards for new, modified, and reconstructed sources moving forward. First, the EPA is proposing regulatory text at 40 CFR 60.5375b(f) to clearly state the requirement to route emissions from wildcat well, delineation well, and low-pressure well completions to a completion combustion device in any instance (unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways). The EPA is aware from implementation of NSPS OOOOa that owners and operators are unclear if they can choose to comply with 40 CFR 60.5375a(f)(3)(ii) and make a claim of technical infeasibility for the separator to function, which then precludes the requirement to route recovered emissions to a completion combustion device. This was not the EPA's intent in NSPS OOOOa and for this reason, we are proposing to clearly specify at 40 CFR 60.5375b(f) that an alternative to route to a separator (instead of routing all flowback to a completion combustion device) is available only when the owner or operator is able to operate a separator and has the separator onsite (or otherwise available for use) and ready for use to comply with the alternative during the entirety of the flowback period.

Second, the EPA is proposing to eliminate recordkeeping requirements which are not necessary for wildcat wells, delineation wells, and low-pressure wells that had previously been included in NSPS OOOOa. Specifically, the EPA is proposing to not require records for ''beneficial'' use of recovered gas (*i.e.,* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve) nor records of ''specific reasons for venting in lieu of capture.'' These records are not required for wildcat wells, delineation wells, and low-pressure wells because the well completion standards at 40 CFR 60.5375b(f) require that all flowback, or gas recovered from flowback through the operation of a separator, be routed to a completion combustion device (*i.e.,* there will not be an instance, when complying with 40 CFR 60.5375b(f), that beneficial use of recovered gas will occur).

G. Centrifugal Compressors

As discussed in section XII.F of the November 2021 proposal preamble (86 FR 63220; November 15, 2021), centrifugal compressors are used throughout the natural gas industry to move natural gas along the pipeline. These compressors are a significant source of methane and VOC emissions. Centrifugal compressors are powered by turbines, which utilize a small portion of the natural gas being compressed to fuel the turbine. As an alternative to natural gas-fueled turbines, some centrifugal compressors use an electric motor.

Centrifugal compressors require seals around the rotating shaft to minimize gas leakage from the point at which the shaft exits the compressor casing. There are two types of seal systems: wet seal systems and mechanical dry seal systems.

Wet seal systems use oil, which is circulated under high pressure between three or more rings around the compressor shaft, forming a barrier to minimize compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. The amount of gas absorbed and entrained by the oil barrier is affected by the operating pressure of the gas being handled; higher operating pressures result in higher absorption of gas into the oil. Seal oil is purged of the absorbed and entrained gas (using heaters, flash tanks and degassing techniques) and recirculated to the seal area for reuse. Gas that is purged from the seal oil is commonly vented to the atmosphere.

Dry seal systems do not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. Emissions occur from dry seals around the compressor shaft vent.

1. NSPS OOOOb

a. November 2021 Proposal

i. Affected Facility

The November 2021 proposal defined the centrifugal compressor affected facility as a single centrifugal compressor using wet seals (including centrifugal compressors using wet seals located at centralized production facilities). The November 2021 proposal excluded centrifugal compressors using wet seals located at a standalone well site from the affected facility definition under NSPS OOOOb.

ii. Summary of Proposed BSER Analysis

November 2021 Proposal BSER Analysis. The BSER analysis methodology presented in the November 2021 proposal (86 FR 63221; November 15, 2021) was consistent with what was used to support the 2011 NSPS OOOO and 2016 NSPS OOOOa BSER analyses. The EPA conducted emissions reduction cost effectiveness analyses for various control options using both the single pollutant and multipollutant approaches.[177]

The EPA used emissions factors for uncontrolled methane emissions from wet seals in the November 2021 proposal analysis that were based on the baseline uncontrolled methane emissions factors used for the 2016 NSPS OOOOa analysis, in addition to the capital costs for flares and associated equipment (*e.g.,* CVS) necessary to route emissions to the flare (with costs updated to 2016 dollars).

[177] See section III.E of this preamble and 86 FR 63154 (November 15, 2021).

These baseline estimates of uncontrolled emissions were higher than the emissions the EPA estimated for these sources in both the 2015–2020 GHGRP subpart W and 2019 GHGI for all industry segments, with the exception of the GHGRP subpart W onshore production and gathering and boosting segments. The reduction in emissions attributed to centrifugal compressors in the 2019 GHGRP subpart W and 2019 GHGI is likely due to the increased deployment of emissions controls resulting from the 2012 NSPS OOOO and 2016 NSPS OOOOa, as well as a shift from the use of wet seals to dry seals by the industry since these rules were promulgated.

Various control options were evaluated as part of the November 2021 proposal to reduce emissions from centrifugal compressors. Such options included control techniques that limit emissions across the rotating shaft of the wet seal centrifugal compressor and techniques to capture and control emissions using a combustion device or by routing to a process. Based on cost analyses conducted, the November 2021 proposal for both the NSPS OOOOb and EG OOOOc rules required that VOC and/or methane emissions from each centrifugal compressor wet seal fluid degassing system be reduced by 95 percent by routing emissions to a control device or to a process.

The November 2021 proposal solicited specific comment on emissions from wet seal compressors, as well as information on lower-emitting wet seal compressor designs. See 86 FR 63221 (November 15, 2021). The EPA also solicited comments on dry seal compressor emissions, seeking information on whether, and to what degree, operational or malfunctioning conditions (*e.g.,* low seal gas pressure, contamination of the seal gas, lack of supply of separation gas, and mechanical failure) have the potential to impact methane and VOC emissions. The EPA further requested information on whether owners and operators of dry seal compressors currently implement standard operating procedures in order to identify and correct operational or malfunctioning conditions that have the potential to increase emissions from dry seal systems. Finally, the EPA also requested information on whether it should consider evaluating BSER and developing NSPS standards for dry seal compressors.

b. Changes to Proposal and Rationale

The EPA is proposing changes and clarifications to the November 2021 proposed standards for NSPS OOOOb. Specifically, we are proposing to: (1)

Revise the affected facility definition to include all centrifugal compressors (*i.e.,* both wet seal and dry seal configurations), (2) specify that self-contained wet seal centrifugal compressors meet the NSPS OOOOb BSER requirements, and (3) set numerical emission limit requirements for dry seal and self-contained wet seal centrifugal compressors.

i. Wet Seal Centrifugal Compressors

The EPA received comments that included specific data on the November 2021 proposal related to emissions, costs, and the proposed standards/analyses for wet seal centrifugal compressors.[178] These commenters asserted that actual wet seal centrifugal compressor baseline emissions are significantly lower than the emissions estimates that the EPA used in the November 2021 proposal's BSER analysis and recommended that the EPA use updated emissions information reported under GHGRP subpart W. One of the commenters provided information on wet seal centrifugal compressor emissions for their sources in the transmission segment and requested the EPA consider using it in any new BSER analysis.[179] This commenter also opined that the proposed 95 percent reduction standard is unclear insofar as there is no indication of what value the reduction is to be measured against. This commenter stated that for seals that emit *de minimis* levels of VOC or methane, it would be impracticable to further reduce such emissions and that assuming emissions can be calculated, the proposed BSER of routing emissions to a control device or to a process would be cost prohibitive.

These same commenters also stated that the costs used by the EPA in the November 2021 proposal's BSER analyses were not representative of actual costs, and that the EPA had underestimated the costs for the control options evaluated. One of the commenters provided detailed cost information that they stated was more representative of actual costs for three combustion scenarios, the option to route to a process for control, and retrofit costs.

Finally, these same commenters suggested that the EPA consider a *de minimis* exemption, such as an exemption for limited use wet seal centrifugal compressors or the establishment of an emissions applicability threshold (referring to California's centrifugal compressor requirements as an example) [180] where a wet seal compressor that has a measured flow rate less than a specified threshold would be exempt from regulatory requirements.

The EPA re-evaluated the November 2021 BSER in light of the suggestions from commenters related to emissions and costs. We used GHGRP subpart W emissions information because the GHGRP requires a multi-step data verification process, which increases the confidence in the reliability of data and resulting analyses.[181] The methodology we used for estimating emissions from compressors is consistent with the methodology used for the November 2021 proposal. See 86 FR 63220 (November 15, 2021). The wet seal centrifugal compressor GHGRP subpart W methane uncontrolled emissions/emissions factors are based on volumetric emissions, which were converted to a mass emission rate for this analysis. The resulting baseline uncontrolled emissions per wet seal centrifugal compressor are 251 tpy methane (69.9 tpy VOC) from wet seal compressors at gathering and boosting sites, 163 tpy methane (45.4 tpy VOC) from wet seal compressors at natural gas processing plants, and 66 tpy methane (1.8 tpy VOC) from wet seal compressors at transmission and storage facilities. These baseline uncontrolled emissions per wet seal centrifugal compressor are higher than what we used in the November 2021 proposal analysis for the gathering and boosting segment (based on GHGRP subpart W emissions factor), but lower for all other segments of the industry.[182]

The same control options from the analysis for the November 2021 proposal (routing to a control device and routing to a process) were evaluated with the above updates. Additionally, we evaluated a new option to address dry seal centrifugal compressor emissions, as discussed in more detail later in this section.

Routing to a control device. As discussed in the November 2021 proposal, a combustion device generally achieves 95 percent reduction of methane and VOC when operated according to the manufacturer instructions. Therefore, for this analysis, we assumed that the entrained natural gas from the seal oil that is removed in the degassing process would be directed to a combustion device that achieves a 95 percent reduction of methane and VOC emissions. The combustion of the recovered gas creates secondary emissions of hydrocarbons (NO_X, CO_2, and CO emissions). Routing the captured gas from the centrifugal compressor wet seal degassing system to a combustion device has associated capital and operating costs. The capital and annual operating costs for the installation of a combustion device used in the updated analysis presented with this supplemental proposal are based on information obtained from commenters regarding a new high-end enclosed combustor.[183] These costs were adjusted from 2021 dollars to 2019 dollars for consistency with the other analyses in this rulemaking. The updated capital costs of $123,559 were annualized at 7 percent based on an equipment life of 10 years. The total annualized capital costs were estimated to be $17,592. The annual operating costs used are based, in part, on costs assumed in the 2011 NSPS OOOO TSD and 2016 NSPS OOOOa TSD,[184] with the costs again updated to reflect 2019 dollars. The resulting annual operating costs (including annual administrative, taxes, and insurance costs) were estimated to be $105,472. Therefore, the updated estimated total annual costs (including annualized capital and operating costs) are $123,063 per compressor. There are no cost savings estimated for this option because the recovered natural gas is combusted.

As a result of the analysis and cost-effectiveness shown in Table 32 below, the EPA has determined that the costs of routing the captured gas from the centrifugal compressor wet seal degassing system to a control device are reasonable for the control of methane for the gathering and boosting, processing and transmission, and storage segments using both the single and multipollutant approaches. The EPA also determined that the costs of routing the captured gas from the centrifugal compressor wet seal degassing system to a control device are reasonable for the control of VOC for the gathering and boosting and processing segments using both the single and multipollutant approaches.

[178] See Document ID Nos. EPA–HQ–OAR–2021–0317–0415 and EPA–HQ–OAR–2021–0317–1375.

[179] See Document ID No. EPA–HQ–OAR–2021–0317–1375.

[180] California's *Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities* rule (California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13, Section 95668(d)(4–9)).

[181] *EPA (2020) Greenhouse Gas Reporting Program.* U.S. Environmental Protection Agency. Data reported as of August 7, 2021.

[182] U.S. Environmental Protection Agency. *Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG).* August 2022.

[183] See Document ID No. EPA–HQ–OAR–2021–0317–1375.

[184] See Document ID Nos. EPA–HQ–OAR–2010–0505–0045 and EPA–HQ–OAR–2010–0505–7631.

Routing to a process. As discussed above, another option for reducing methane and VOC emissions from the compressor wet seal fluid degassing system is to route the captured emissions back to the compressor suction or fuel system or put them to another beneficial use (referred to collectively as ''routing to a process''). One opportunity to meet this requirement would be to route emissions via a CVS or to any enclosed portion of a process unit (*e.g.,* compressor or fuel gas system) where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. For purposes of this analysis, we assumed that routing methane and VOC emissions from a wet seal fluid degassing system to a process reduces methane and VOC emissions in amounts greater than or equal to the emissions that would be reduced by a combustion device (*i.e.,* greater than or equal to 95 percent) because emissions are conveyed via a CVS to an enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process. There are no secondary impacts with the option to control emissions from centrifugal wet seals by capturing gas and routing to a process. This alternative is an existing compliance option under NSPS OOOO and NSPS OOOOa. The EPA has historically assumed that the emissions reduced by routing to a process are 95 percent or greater. Our understanding is that routing gas from centrifugal compressor wet seal fluid degassing systems to a process generally requires the use of a VRU or other treatment to obtain a gas stream composition suitable to be returned to the sales line or for use for another purpose. Unlike pneumatic controllers and pneumatic pumps, (see section IV.D.1.b.iii of this preamble for controllers and section IV.E.1.b.iii of this preamble for pumps), the need to use a VRU or other treatment to obtain a gas stream with a composition suitable to be returned to the sales line could result in the use of treatment components that may vent to the atmosphere or the need for maintenance where, for example, the VRU may need to be bypassed for short periods (resulting in venting of some emissions to the atmosphere). The EPA solicits comment on its assumption that the emissions reduced by requiring the capture of gas and routing to a process is 95 percent or greater. The EPA also is soliciting comment on the prevalence of owners and operators complying with NSPS OOOO and NSPS OOOOa or other rules by routing emissions from the wet seal fluid degassing system to a process and the need for a VRU in order to be able to route emissions from the wet seal fluid degassing system to a process.

The capital and annual costs for routing the seal oil degassing system to a process used in the updated analysis are based on information obtained from commenters.[185] The updated capital costs are estimated to be $600,636, and the annual costs were estimated to be $85,517 (without savings), assuming a 10-year equipment life at 7 percent interest. Because the natural gas is not lost or combusted, the value of the natural gas represents a savings to owners and operators in the production (gathering and boosting) and processing segments. Savings were estimated using a natural gas price of $3.13 per thousand cubic feet (Mcf), which resulted in annual savings of $43,329 per year at gathering and boosting stations and $28,164 per year at processing plants.

The updated analysis and cost effectiveness shown in Table 32 indicates that routing emissions to a process is cost effective for the control of methane emissions for all of the evaluated segments using the single pollutant approach and is also cost effective for methane using the multipollutant approach for the gathering and boosting and processing segments. Similarly, the updated analysis indicates that routing emissions to a process for the control of VOC for the gathering and boosting and processing segments is cost effective using both the single and multipollutant approaches. However, as noted in the November 2021 proposal, although capturing leaking gas and routing to a process has the advantage of both reducing emissions by at least 95 percent and capturing the natural gas (which results in natural gas savings), the EPA has received feedback that this option may not be viable in situations where downstream equipment capable of handling a low-pressure fuel source is unavailable.

Maintenance and repair activities to meet numerical emission limit. The EPA evaluated a third BSER option for this supplemental proposal not considered for the November 2021 proposal: maintenance and repair activities conducted to maintain emissions at or below 3 scfm, with annual flow rate monitoring on the wet seal degassing vent (also referred to as the numerical emission limit). We did so based on comments indicating that a threshold monitoring option is a more practical option for low-emitting centrifugal compressors with wet seals (as compared to the proposed requirement to route to a control device or to a process). This option would require owners and operators to perform periodic flow rate monitoring, as well as preventative maintenance and repair as necessary, on the wet seal degassing vent to ensure compliance with the 3 scfm emission limit. The 3 scfm volumetric flow rate emission limit is the same monitoring limit included in California's Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.[186] California developed the 3 scfm emission standard because this was the equivalent to an average dry seal emission rate.[187] The commenters specifically noted that low emissions from centrifugal compressors equipped with wet seals are largely a function of proper maintenance and that requiring a 95 percent reduction standard or routing to a process creates an unintended result—the more careful an operator is with maintaining its wet seals, the more difficult and costly (on a cost-per-ton basis) controlling emissions in compliance with these requirements becomes.[188]

The types of maintenance and repair actions that may be needed to maintain emissions at or below 3 scfm will vary considerably. One commenter,[189] a company that institutes an annual monitoring plan, indicated that the actions needed to reduce emissions or maintain a compressor such that it is low-emitting can range from correcting an identified issue immediately with minor maintenance, replacing o-rings on the filtration system, or having to rebuild the entire oil system. The costs associated with these maintenance and corrective actions vary significantly, from limited labor costs for a short repair activity to a significant capital cost of equipment and labor to repair and/or replace parts of the compressor. The EPA does not have specific costs for the range of maintenance and/or repairs

[185] See Document ID No. EPA–HQ–OAR–2021–0317–1375.

[186] California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13, Section 95668(d)(4–9).

[187] State of California. *Air Resources Board Public Hearing to Consider the Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. Staff Report: Initial Statement of Reasons*. pg. 100.

[188] See Document ID No. EPA–HQ–OAR–2021–0317–1375.

[189] See Document ID No. EPA–HQ–OAR–2021–0317–1375.

that may be necessary to maintain a flow rate at or below than 3 scfm. For the purposes of this analysis, the EPA selected an annual cost of $25,000 to represent the average cost of performing the monitoring and the necessary compressor wet seal maintenance. While we recognize certain types of maintenance or corrective actions may result in costs higher than $25,000 in one year, we believe that this is a conservative estimate to represent an average, annual cost. The EPA specifically solicits comments on the types of maintenance or corrective actions that may be required to maintain an emission rate of 3 scfm or less from wet seal degassing, along with representative costs.

To estimate the cost effectiveness of this option, the EPA used the same updated GHGRP subpart W "uncontrolled" emissions discussed above for each centrifugal compressor with wet seals to represent baseline emissions. The "after control" emissions levels were calculated based on 3 scfm volumetric flow for 8,760 hours per year and the representative composition of the gas in the different segments. This calculation assumes that the emissions are, on average, 3 scfm for the entire year. This represents a conservative estimate, as one commenter[190] indicated that the implementation of a similar program resulted in average measured emissions of less than 0.5 scfm for compressors with wet seals. Table 31 shows the baseline emissions, the emissions after implementation of the numerical emission limit, and the emission reductions for wet seal compressors.

TABLE 31—METHANE BASELINE EMISSIONS AND REDUCTIONS AFTER IMPLEMENTATION OF THE NUMERICAL EMISSION LIMIT (REQUIREMENT TO MAINTAIN FLOW RATE AT OR BELOW 3 SCFM) OPTION—WET SEAL COMPRESSORS

Segment	Methane emissions (tpy)/compressor		Methane emission reduction (tpy)
	Baseline [a]	After implementation	
Gathering and Boosting	251	27	224
Processing	163	27	136
Transmission and Storage	66	30	35

[a] From GHGRP subpart W (Reporting Years 2015 to 2020—Average).
[b] Calculated assuming total gas emissions are 3 scfm for 8,760 hours.

As noted above, we assumed annual maintenance, monitoring, and corrective action costs of $25,000 (without savings). Because the natural gas is not lost or combusted, the value of that natural gas represents a savings to owners and operators in the production (gathering and boosting) and processing segments. Savings were estimated using the emission reductions noted above and a natural gas price of $3.13 per Mcf, which resulted in annual savings of $33,719 per year at gathering and boosting stations and $20,486 per year at processing plants.

As a result of the wet seal centrifugal compressor analysis and cost effectiveness shown in Table 32, the EPA has determined that the costs of implementing a numerical emission limit are reasonable for the control of methane for the gathering and boosting, processing, and transmission and storage segments using both the single and multipollutant approaches. The EPA has also determined that the costs of implementation of a numerical emission limit is reasonable for the control of VOC for the gathering and boosting and processing segments, using both the single and multipollutant approaches.

The estimated cost effectiveness values that would be associated with: (1) Capturing and routing emissions to a combustion device, (2) capturing and routing emissions to a process, and (3) conducting maintenance and repair activities to meet a numerical emission limit (3 scfm) (referred to as the "numerical limit of 3 scfm") for compressors with wet seals are provided in Table 32. In addition to the cost effectiveness values, Table 32 provides a conclusion regarding whether the estimated cost effectiveness value is within the range that the EPA has typically considered to be reasonable. The "overall" reasonableness determination is classified as "Y" if the cost effectiveness of either methane or VOC is within the range that the EPA considers reasonable for that pollutant, or "N" if both the methane and VOC cost effectiveness values are beyond the range that the EPA considers reasonable on a multipollutant basis.

TABLE 32—SUMMARY OF WET SEAL CENTRIFUGAL COMPRESSOR COST EFFECTIVENESS BY REGULATORY OPTION AND INDUSTRY SEGMENT

Segment/regulatory option	Cost effectiveness ($/ton) [a]—reasonable?				Overall [a]
	Single pollutant		Multipollutant		
	Methane	VOC	Methane	VOC	
Gathering and Boosting:					
Regulatory Option One—Route Emissions to Combustion Device	$515–Y	$1,853–Y	$258–Y	$927–Y	Y
Regulatory Option Two—Route Emissions to the Process	879–Y	3,163–Y	440–Y	1,582–Y	Y
Regulatory Option Three—Numerical Limit of 3 scfm	111–Y	401–Y	56–Y	201–Y	Y
Processing:					

[190] See Document ID No. EPA–HQ–OAR–2021–0317–1375.

TABLE 32—SUMMARY OF WET SEAL CENTRIFUGAL COMPRESSOR COST EFFECTIVENESS BY REGULATORY OPTION AND INDUSTRY SEGMENT—Continued

Segment/regulatory option	Cost effectiveness ($/ton) [a]—reasonable?				Overall [a]
	Single pollutant		Multipollutant		
	Methane	VOC	Methane	VOC	
Regulatory Option One—Route Emissions to Combustion Device	793–Y	2,851–Y	396–Y	1,425–Y	Y
Regulatory Option Two—Route Emissions to the Process	1,353–Y	4,866–Y	676–Y	2,433–Y	Y
Regulatory Option Three—Numerical Limit of 3 scfm	183–Y	660–Y	92–Y	330–Y	Y
Transmission and Storage:					
Regulatory Option One—Route Emissions to Combustion Device	1,973–Y	71,240–N	987–Y	35,620–N	Y
Regulatory Option Two—Route Emissions to the Process	3,369–N	121,607–N	1,684–Y	60,804–N	Y
Regulatory Option Three—Numerical Limit of 3 scfm	711–Y	25,650–N	355–Y	12,825–N	Y

[a] For the gathering and boosting and processing segments, the owners and operators realize the savings for the natural gas that is not emitted and lost. The cost effectiveness values shown do not consider these savings. Note that the consideration of savings does not impact whether the cost effectiveness of any of these options falls within the ranges considered reasonable by the EPA.

[b] For overall cost effectiveness to be considered reasonable, either the cost effectiveness of methane or VOC on a single pollutant basis must be within the ranges considered reasonable by the EPA, or the cost effectiveness of both methane and VOC on a multipollutant basis must be within the ranges considered reasonable by the EPA.

Summary of Control Options Evaluated. In summary, the EPA evaluated three options for wet-seal centrifugal compressors: (1) Route emissions to a control device, (2) route emissions to a process, and (3) conduct maintenance and repair to maintain emissions at or below 3 scfm. The EPA's relevant analyses found that, for all segments, the costs in relation to the emission reductions were reasonable for all three options. However, the options to route captured gas to a control device or to a process achieve greater emission reductions than conducting maintenance and repair to maintain 3 scfm. For example, for the gathering and boosting segment, we estimated that the emissions reduced under the 3 scfm numerical limit option for a representative centrifugal compressor to be 89 percent, which is less than the routing to a control or process options, which achieve 95 percent.[191] Therefore, the EPA finds that the standard of performance for each centrifugal compressor using a wet seal is 95 percent reduction of methane and VOC emissions based on a BSER of capturing and routing emissions from the wet seal degassing system to a combustion device for new sources in the gathering and boosting, processing, and transmission and storage segments. These reductions can also be achieved by routing emissions from the wet seal degassing system to a process. Therefore, as a compliance alternative, the EPA proposes to allow owners and operators to meet the 95 percent standard of performance by routing emissions from the wet seal degassing system to a process. The EPA notes that if an owner or operator chooses to route to a process to meet the 95 percent level of control, there are no secondary impacts. If an owner or operator chooses to route to a combustion device to meet the 95 percent level of control, the combustion of the recovered gas creates secondary emissions of hydrocarbons (NO_X, CO_2, and CO emissions).

As discussed in section III.D of this preamble, NSPS KKK includes standards for controlling VOC emissions from centrifugal compressors with wet seals at natural gas processing plants. The standards provide several options for compliance, including: (1) Operating the centrifugal compressor with the barrier fluid at a pressure greater than the compressor stuffing box pressure; (2) equipping the centrifugal compressor with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a CVS to a control device that reduces VOC emissions by 95 percent or more; or (3) equipping the centrifugal compressor with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere. NSPS KKK exempts compressors from these requirements if the compressor is either equipped with a CVS to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that reduces VOC emissions by 95 percent, or if the compressor is designated for no detectable emissions.

For NSPS OOOOb, we are proposing that emissions from each centrifugal compressor wet seal fluid degassing system require routing to a control device that achieves a 95 percent reduction of VOC and methane emissions, or by routing the emissions to a process that achieves 95 percent reduction of VOC and methane emissions. Proposed NSPS OOOOb is equivalent to one of the three options available under NSPS KKK.

Owners and operators of wet seal centrifugal compressors have been complying with NSPS KKK since 1984. The EPA is requesting comments on whether it would provide more regulatory consistency for owners, operators, and implementing agencies if NSPS OOOOb were to incorporate all compliance options provided in NSPS KKK for wet seal centrifugal compressors at natural gas processing plants, as opposed to only proposing the compliance option of routing to a control or process proposed in this supplemental proposal.

ii. Lower-Emitting/Self-Contained Wet Seal Compressor Designs

The November 2021 proposal solicited comment and information on lower-emitting wet seal compressor designs. Commenters [192] reported that the process for wet seal degassing varies throughout the industry, and some manufacturers have a configuration that is essentially a closed process that ports the degassing emissions into the natural

[191] U.S. Environmental Protection Agency. *Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG).* Supporting Spreadsheets. August 2022.

[192] See Document ID No. EPA–HQ–OAR–2021–0317–0415.

gas line at the compressor suction. According to one industry commenter that employs this type of wet seal centrifugal compressor, this configuration typically includes a primary chamber where initial degassing occurs (and is recovered), and chamber(s) with air sparging to release and recover residual gas volumes entrained in the oil. Rather than venting all of the de-gassing volumes, the emissions are routed back to suction directly from the degassing/sparging chambers; the oil is ultimately recycled to the lube oil tank where any small amount of residual gas is released through a vent. One commenter stated that field evaluation is not always feasible for this closed system configuration but reported that testing and modeling demonstrates that the residual natural gas volume vented is very small (much less than 1 percent of the total degassed natural gas volume). Another commenter requested that the EPA clarify that certain existing closed-loop wet seal systems be exempted from any regulatory proposal, or at a minimum, that such systems should be considered in compliance with the BSER currently applicable to wet seals.[193]

Based on information indicating that closed-loop (self-contained) systems are inherently low-emitting, the EPA is proposing that these and similarly designed, self-contained wet seal centrifugal compressors represent/meet BSER (consistent with the routing to a process or control option). The EPA is proposing a definition for a ''self-contained wet seal compressor'' as a ''wet seal compressor system that is a closed process that ports the degassing emissions into the natural gas line at the compressor suction (*i.e.,* degassed emissions are recovered).'' The de-gas emissions are routed back to suction directly from the degassing/sparging chambers, and the oil is ultimately recycled to the lube oil tank where any small amount of residual gas is released through a vent. While the EPA recognizes the low emissions associated with these self-contained wet seal centrifugal compressors, we also recognize that there could be increased emissions due to leaks or malfunctions. Therefore, the proposed rule includes the requirement that owners or operators of self-contained wet seal centrifugal compressors must comply with the 3 scfm numerical emission standard described below for centrifugal compressors with dry seals. As indicated above, the intent of requiring compliance with the 3 scfm numerical standard is to ensure that self-contained wet seal compressors are operating properly (without leaks or malfunctions) since EPA understands that these compressors emit trivial amounts (*i.e.,* achieve greater than 99 percent control) when properly operated. The EPA recognizes that where there is venting of any emissions from these compressors, emissions would more than likely be nondetectable for leaks, or would be at a rate lower than 3 scfm. The EPA solicits comment on, and support for, whether a lower numerical limit is needed to demonstrate proper operation of self-contained wet seal centrifugal compressors and/or equivalency to the BSER. The EPA also solicits comment on the feasibility of measuring the flow rate of self-contained wet seal centrifugal compressors at a rate lower than 3 scfm.

In addition to wet seal compressor systems that are self-contained, one commenter[194] reported information on another wet seal compressor that was inherently low-emitting. The commenter stated that it has facilities that use mechanical wet seals that generally have zero emissions. They explained that the metal (tungsten carbide) is seated against carbide, with oil pressing against the outside of the actual seal. They noted that because the oil is not in contact with the natural gas for these mechanical seals, these wet seals generally have zero degassing emissions. The commenter requested that the EPA exclude compressors utilizing mechanical wet seals from the wet seal compressor requirements otherwise applicable to wet seal compressors. The EPA is continuing to evaluate mechanical wet seal designs and the comments it has already received on the issue, and is soliciting additional information on these and other wet seal compressor designs (with supporting emissions information) that are inherently low-emitting under operating conditions.

iii. Dry Seal Compressors

The EPA solicited comments on dry seal compressor emissions and whether, and to what degree, operational or malfunctioning conditions (*e.g.,* low seal gas pressure, contamination of the seal gas, lack of supply of separation gas, mechanical failure) have the potential to impact methane and VOC emissions. The EPA further requested information on whether owners and operators implement standard operating procedures to identify and correct operational or malfunctioning conditions that have the potential to increase emissions from dry seal systems, and whether EPA should consider evaluating BSER and developing NSPS standards for dry seal compressors.

As the EPA has heard previously, the commenters noted that some dry seal compressors have higher emissions than compressors with wet seals. Based on input from a couple of commenters, we estimated the cost effectiveness of conducting preventative maintenance and repair, as needed, to maintain the volumetric flow rate from each centrifugal compressor that uses a dry seal at or below 3 scfm (as done for those with wet seals). The 3 scfm volumetric flow rate emission limit is the same monitoring limit included in California's Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities for wet seal compressors.[195] California developed the 3 scfm emission standard because this was the equivalent to an average dry seal emission rate.[196] The EPA did not evaluate any other control options for compressors with dry seals because they are inherently low-emitting; increased emissions are generally the result of either unforeseen upset conditions or poor maintenance.

To estimate the cost effectiveness of this option, we used the 2019 GHGI ''uncontrolled'' emissions for dry seal compressors as the baseline.[197] The ''after control'' emissions levels were calculated based on a threshold of 3 scfm volumetric flow for 8,760 hours per year and the representative composition of the gas in the different segments. This calculation assumes that the emissions are, on average, 3 scfm for the entire year. Table 33 shows the baseline emissions, the emissions after implementation of the numerical emission limit, and the emission reductions for dry seal compressors. The 3 scfm volumetric flow emission limit is the same as described above for wet seal centrifugal compressors.

[193] See Document ID No. EPA–HQ–OAR–2021–0317–1375.

[194] See Document ID No. EPA–HQ–OAR–2021–0317–0415.

[195] California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4, Subarticle 13, Section 95668(d)(4–9).

[196] State of California. Air Resources Board Public Hearing to Consider the Proposed Regulation for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. Staff Report: Initial Statement of Reasons. pg. 100.

[197] GHGI-Dry Seals.

TABLE 33—METHANE BASELINE EMISSIONS AND REDUCTIONS AFTER IMPLEMENTATION OF THE ANNUAL EMISSION LIMIT (REQUIREMENT TO MAINTAIN FLOW RATE AT OR BELOW 3 SCFM) OPTION—DRY SEAL COMPRESSORS

Segment	Methane emissions (tpy)		Methane emission reduction (tpy)
	Baseline [a]	After implementation	
Gathering and Boosting	36	6	30
Processing	28	1	27
Transmission and Storage	44	6	38

[a] Based on GHGI. Emissions from dry-seal compressors are not estimated for gathering and boosting in the GHGI. The baseline emissions were calculated from the transmission and storage emissions (adjusted for the difference in gas composition).

As discussed above for wet seal centrifugal compressors, there is a wide range in the types of repairs needed (and associated costs) for dry seal compressors. Given the lack of specific information on these repairs and costs, we assumed the annual costs to comply with this option to be $15,000 (without savings). This assumption is lower than the comparable assumption for wet seals because annual operating and maintenance costs for compressors with dry seals are lower than for compressors with wet seals. The EPA specifically solicits comments on the types of maintenance and corrective actions that may be required to maintain an emissions rate of 3 scfm or less from centrifugal compressors with dry seals, along with representative costs.

Because natural gas emissions from a centrifugal compressor with dry seals would be reduced by maintaining the emission rate at or below 3 scfm, the value of the retained natural gas that would have otherwise been emitted represents a savings to owners and operators in the production (gathering and boosting) and processing segments. Savings were estimated using the emission reductions noted above and a natural gas price of $3.13 per Mcf, which resulted in annual savings of $2,425 per year at gathering and boosting stations and $1,170 per year at processing plants.

The estimated cost effectiveness values that would be associated with conducting maintenance and repair activities to meet a numerical emission limit of 3 scfm for dry seal compressors are provided in Table 34. In addition to the cost effectiveness values, Table 34 provides a conclusion regarding whether the estimated cost effectiveness value is within the range that the EPA has typically considered to be reasonable. The ''overall'' reasonableness determination is classified as ''Y'' if the cost effectiveness of either methane or VOC is within the range that the EPA considers reasonable for that pollutant, or ''N'' if both the methane and VOC cost effectiveness values are beyond the range the EPA considers reasonable on a multipollutant basis.

TABLE 34—SUMMARY OF DRY SEAL CENTRIFUGAL COMPRESSOR COST EFFECTIVENESS BY INDUSTRY SEGMENT—NUMERICAL LIMIT OF 3 SCFM

Segment	Cost effectiveness ($/ton) [a]—reasonable?				Overall [b]
	Single pollutant		Multipollutant		
	Methane	VOC	Methane	VOC	
Gathering and Boosting	930–Y	3,346–Y	$465–Y	$1,673–Y	Y
Processing	1,927–Y	6,933–N	964–Y	3,467–Y	Y
Transmission and Storage	831–Y	29,997–N	415–Y	14,999–N	Y

[a] For the gathering and boosting and processing segments, the owners and operators realize the savings for the natural gas that is not emitted and lost. The cost effectiveness values shown do not consider these savings. Note that the consideration of savings does not impact whether the cost effectiveness of any of these options falls within the ranges considered reasonable by the EPA.

[b] For overall cost effectiveness to be considered reasonable, either the cost effectiveness of methane or VOC on a single pollutant basis must be within the ranges considered reasonable by the EPA, or the cost effectiveness of both methane and VOC on a multipollutant basis must be within the ranges considered reasonable by the EPA.

Based on the consideration of the costs in relation to the emission reductions for methane shown in Table 34, the costs to implement the option to conduct preventative repair and maintenance so that each centrifugal compressor with a dry seal maintains a volumetric flow rate at or below 3 scfm is reasonable for all segments under both the single pollutant and multipollutant approaches. Based on the consideration of the costs in relation to the emission reductions for VOC, the costs of this option are reasonable for the gathering and boosting segment under both the single pollutant and multipollutant approaches. For the processing segment, the costs for reducing VOC emissions are reasonable under the multipollutant approach, but not the single pollutant approach. Costs for reducing VOC emissions would not be reasonable for implementing this approach for the transmission and storage segment. Given that the costs of conducting preventative repair and maintenance activities in order to maintain the volumetric flow rate from each centrifugal compressor with a dry seal at or below 3 scfm are reasonable, the EPA is proposing this option as BSER for compressors with dry seals.

c. Summary of 2022 Proposal

i. Affected Facility

Based on changes made and discussed in section IV.G.1.b of this preamble, the EPA is proposing to redefine the affected facility to include dry seal centrifugal compressors in addition to wet seal centrifugal compressors. Therefore, a centrifugal compressor affected facility would be defined as a single centrifugal compressor. Further, the EPA is maintaining the proposed specifications from the November 2021 proposal as applicable to centrifugal compressors located at well sites and centralized production facilities. Specifically, centrifugal compressors located at centralized production facilities would be considered affected facilities, while those located at well sites would not be affected facilities under NSPS OOOOb.

ii. Requirements

Wet Seal Centrifugal Compressors. The EPA is proposing that owners or operators of centrifugal compressor affected facilities with wet seals must comply with the GHG and VOC standards by reducing methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent. As an alternative to routing the CVS to a control device, an owner or operator may also route the CVS to a process or utilize a self-contained wet seal centrifugal compressor. If an owner or operator chooses to comply with this requirement either by using a control device to reduce emissions or by routing to a process to reduce emissions, an owner or operator must equip the wet seal fluid degassing system with a cover and the cover must be connected through a CVS meeting specified requirements (40 CFR 60.5411b(a) through (c)), such as design and operation with no identifiable emissions, as described in section IV.K of this preamble. If an owner or operator uses a self-contained wet seal centrifugal compressor, an owner or operator must ensure a volumetric flow rate at or below 3 scfm. In addition to the flow rate monitoring required every 8,760 hours, additional preventative or corrective measures may be required to ensure compliance.

Dry Seal Centrifugal Compressors. The EPA is proposing that the standard of performance for centrifugal compressor dry seals is 3 scfm. The proposed BSER is for an owner or operator to conduct preventative maintenance and repair of their centrifugal compressors that use dry seals, as needed, to maintain the volumetric flow rate from each centrifugal compressor that uses a dry seal at or below 3 scfm. Owners and operators of centrifugal compressors with dry seals must conduct volumetric emissions measurements from each centrifugal compressor dry seal vent on or before 8,760 hours of operation or previous measurement and must use specified methods (similar to the flow rate monitoring requirements specified under the GHGRP subpart W) in doing so. Owners or operators must ensure that the volumetric emission measurements (in operating mode or in stand-by-pressurized-mode) from each centrifugal compressor dry seal vent are less than or equal to a flow rate 3 scfm (in operating or standby pressurized mode) or a manifolded dry seal compressor flow rate less than or equal to the number of compressors multiplied by 3 scfm (in operating or standby pressurized mode). As discussed in section IV.I the EPA is proposing the use of volumetric flow rate which meet the requirements of Method 2D (40 CFR part 60, appendix A) for testing emissions from reciprocating compressor rod packing and the use of a high-volume sampler to measure the emissions from either the reciprocating compressor rod packing or centrifugal compressor seal vent (dry seals for NSPS OOOOb and all centrifugal compressor wet and dry seals for EG OOOOc). For the high-volume sampler, instead of relying on manufacturer defined procedures required in GHGRP Subpart W, the EPA is proposing a defined set of procedures and performance objectives to ensure consistent application of these samplers. In an effort to allow for additional innovation for these types of measurements, the EPA is also proposing to allow other methods, subject to Administrator approval, that have been validated according to Method 301 (40 CFR part 63, appendix A). Preventative maintenance or other corrective actions may be necessary (in addition to the monitoring every 8,760 hours of operation) in order for owners or operators to ensure compliance at all times (consistent with the general duty clause 40 CFR 60.5470b(b)) with the required flow rate of 3 scfm or less.

Recordkeeping and Reporting Requirements. Specific recordkeeping and reporting requirements would also apply for each wet seal centrifugal compressor affected facility. Specifically, records and annual reporting that identifies each centrifugal compressor using a wet seal system that was constructed, modified, or reconstructed during the reporting period would be required. In instances where a deviation from the standard occurred during the reporting period and recorded, an owner or operator would be required to provide information on the date and time the deviation began, the duration of the deviation, and a description of the deviation.

For centrifugal compressors where compliance is achieved by using a control device to reduce emissions, the following information would be required in the annual report: dates of the cover and CVS inspections, whether defects or leaks are identified, and the date of repair or the date of anticipated repair if repair is delayed. Where bypass requirements apply, reporting of the date and time of each bypass alarm or each instance the key is checked out would be required.

If complying with the centrifugal compressor requirements for wet seal fluid degassing system by reducing VOC and methane emissions by 95 percent using a control device tested by the device manufacturer, the annual report must include: the identification of the compressor with the control device and the make, model, and date of purchase of the control device. An owner or operator would also be required to record and report the following: (1) Each instance where there is an inlet gas flow rate exceedance, (2) each instance where there is no indication of a pilot flame, and (3) each instance where there was a visible emissions exceedance. The annual report would be required to include the date and time the deviation began, the duration of the deviation, and a description of the deviation. Finally, for each visible emissions test following return to operation from a maintenance or repair activity, the annual report would be required to include the date of the visible emissions test, the length of the test, and the amount of time visible emissions were present.

If complying with the centrifugal compressor requirements for a wet seal fluid degassing system by reducing VOC and methane emissions by 95 percent by using a control device not tested by the device manufacturer, the following information must be included in the annual report: identification of the control device not tested by the device manufacturer, the identification of the compressor with the tested control device, the date the performance test was conducted, the pollutant(s) tested, and the performance test report conducted to demonstrate that the control device is achieving, at a minimum, the required 95 percent reduction.

For each dry seal centrifugal compressor affected facility and self-contained wet seal centrifugal compressor affected facility, owners and operators would be required to track and report the cumulative number of hours of operation since startup since the previous screening/volumetric emissions measurement in order to demonstrate compliance with their volumetric emissions measurements. Additionally, a description of the method used and the results of the volumetric emissions measurement or emissions screening, as applicable, would be required in the annual report.

2. EG OOOOc

a. Summary of 2021 Proposal

The summary of the November 2021 proposal for EG OOOOc is consistent with what was proposed for NSPS OOOOb (see section IV.G.1.a of this preamble).

b. Changes to Proposal and Rationale

The EPA is proposing changes and specific clarifications to the November 2021 proposal presumptive standards for the EG OOOOc. Specifically, we are proposing to: (1) Revise the designated facility definition to include all centrifugal compressors, (2) include a numerical emission limit requirements for dry and wet seal compressors, and (3) allow owners and operators the option to comply with EG OOOOc by reducing methane emissions by 95 percent by either routing to a control device or to a process. The basis for these changes is presented below.

Wet Seal Centrifugal Compressors. Industry commenters expressed particular concern about having to retrofit existing wet seal centrifugal compressors to accommodate the November 2021 proposal that would have required owners and operators to reduce methane emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent or greater. One commenter[198] stated that the November 2021 proposal for wet seal centrifugal compressors would require installation of an enclosed combustion device or a process flare in nearly every case for their facilities. The commenter noted that, while theoretically an enclosed combustion device could be installed to control the minimal emissions on an individual wet seal compressor, a combustion device cannot be located just anywhere, especially not in close proximity to a transmission compressor station. The commenter noted that a combustion device must be strategically located away from combustible materials, which typically requires a significant footprint, aboveground piping (above roadways), and in an elevated location. In order to install such a device, they stated that they would likely have to apply for and receive state and local permit modifications, which are not certain to be approved in each case. The commenter also stated that routing to a control device could present safety concerns. For example, they note that attempts to capture a low-pressure natural gas vent stream, such as that of the wet seal, could result in inducing air into the gas stream, potentially creating a combustible mixture. The commenter reports that one manufacturer has previously ''caution[ed] the use of flaring with gas seal vented emissions due to risk of the potential explosive hazard and back-flashing.''[199] The commenter reports that it is ''[their] view (concurrent with many users of our equipment) [that] flaring of compressor seal emissions can introduce inherently dangerous conditions with the potential for back-flashing and serious risk of explosion. Solar therefore discourages flaring for this reason although some customers have successfully implemented it.''

With respect to the routing to process option, the same commenter notes that, while theoretically feasible, a low flow gas stream (like their facilities' gas streams) cannot be safely or technically re-introduced back into their processes without significant, resource-intensive, attention to that minor emissions stream. According to the commenter, the unintended result would be that the additional equipment that would need to be installed to accomplish this routing back to process would not only be costly (discussed below) but could also result in additional emissions from other sources.

Based on these concerns, for existing wet seal centrifugal compressors, the EPA is no longer proposing that BSER is 95 percent reduction of methane emissions by routing emissions to a control device or process. Instead, based on the updated analysis presented in this supplemental proposal, the EPA is proposing that the standard of performance for existing sources is a numerical emission limit of 3 scfm; the BSER is for an owner or operator to conduct preventative maintenance and repair of their centrifugal compressors that use wet seals, as needed, to maintain the volumetric flow rate from each centrifugal compressor that uses a wet seal at or below 3 scfm. Owners or operators would be required to conduct volumetric flow rate measurements at least every 8,760 hours. As a compliance alternative, the EPA is proposing to allow owners and operators the option to reduce methane emissions by 95 percent or greater by routing emissions to a control device or to a process, which would achieve emissions reductions equal to or greater than the standard of performance of 3 scfm. The cost of application of the numerical emission limit requirement at an existing source is the same as at a new source, and the methane cost effectiveness would be the same as discussed in the previous section for wet seal centrifugal compressors subject to NSPS OOOOb. The cost effectiveness (without natural gas savings) of complying with the numerical emission limit for methane emissions is approximately $111 per ton of methane emissions reduced for the gathering and boosting segment, $183 per ton of methane emissions reduced for the processing segment, and $711 per ton of methane emissions reduced for the transmission and storage segment. Considering natural gas savings, the cost effectiveness of complying with the numerical emission limit for methane emissions is an overall net savings for the gathering and boosting segment, and $28 per ton of methane emissions reduced for the processing segment.

As discussed in section IV.G.1.i of this preamble NSPS KKK includes standards for controlling VOC emissions from centrifugal compressors with wet seals at natural gas processing plants. The standards provide several options to comply, including: (1) Operating the centrifugal compressor with the barrier fluid at a pressure that is greater than the compressor stuffing box pressure; (2) equipping the centrifugal compressor with a barrier fluid system degassing reservoir that is routed to a process or fuel gas system or connected by a CVS to a control device that reduces VOC emissions by 95 percent or more; or (3) equipping the centrifugal compressor with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere. NSPS KKK exempts compressors from these requirements if the compressor is either equipped with a CVS to capture and transport leakage from the compressor drive shaft back to a process or fuel gas system or to a control device that reduces VOC emissions by 95 percent, or if the compressor is designated for no detectable emissions.

For EG OOOOc, the proposed presumptive standard would be a numerical emission limit of 3 scfm and include an alternative compliance method of reducing methane emissions by 95 percent by routing to a control or process. The proposed presumptive standard of 3 scfm is less stringent than the regulatory compliance options under NSPS KKK for centrifugal compressor at natural gas processing plants.

Owners and operators of wet seal centrifugal compressors have been complying with NSPS KKK since 1984. The EPA is requesting comments on whether it would provide more

[198] See Document ID No. EPA–HQ–OAR–2021–0317–1375.

[199] See Document ID No. EPA–HQ–OAR–2021–0317–1375.

regulatory consistency for owners, operators, and implementing agencies if EG OOOOc were to incorporate all compliance options provided in NSPS KKK for wet seal centrifugal compressors at natural gas processing plants instead of the 3 scfm emission limitation.

Dry Seal Compressors. The application of the numerical emission limit option at an existing source is the same as at a new source because no additional equipment must be installed in order to comply with the standards. Therefore, the cost of control would also be the same (see section IV.G.1.b.i of this preamble). As a result, based on the consideration of the costs in relation to the emission reductions for methane, the costs to implement the numerical emission limit is reasonable for all segments. Given that the costs of reducing methane emissions by the implementation of the numerical emission limit are reasonable, the EPA is proposing this option as BSER for existing centrifugal compressors with dry seals.

c. Summary of 2022 Proposal

i. Designated Facility

Based on changes made and discussed under section IV.F.2.b of this preamble, the EPA is proposing to redefine the designated facility to include dry seal compressors in addition to wet seal compressors. Specifically, the designated facility is defined as a single centrifugal compressor. Further, the EPA is proposing that centrifugal compressors located at centralized production facilities would be designated facilities, while centrifugal compressors located at well sites would not be designated facilities, consistent with the November 2021 proposal.

ii. Requirements

Wet and Dry Seal Centrifugal Compressors. The EPA is proposing that owners or operators of centrifugal compressors with wet and dry seals be required to conduct volumetric emission measurements (in operating mode or in stand-by-pressurized-mode) from each centrifugal compressor dry and wet seal vent using specified methods (similar to the flow rate monitoring requirements specified under GHGRP subpart W). Owners and operators would be required to conduct volumetric emissions measurements from each centrifugal compressor wet and dry seal vent on or before 8,760 hours of operation or previous measurement.

The volumetric emissions measurement of the centrifugal compressor wet and dry seal vent must be maintained to be less than or equal to a flow rate of 3 scfm (in operating or standby pressurized mode) or a manifolded dry and wet seal compressor flow rate less than or equal to the number of compressors multiplied by 3 scfm (in operating or standby pressurized mode). The same requirements specified in IV.G.1.c of this preamble for dry seal compressors complying with the numerical emission limit being proposed for NSPS OOOOb are being proposed for self-contained wet seal centrifugal compressors under NSPS OOOOb and for dry and wet seal centrifugal compressors complying with this option under EG OOOOc.

Compliance Alternative for Wet Seal Compressors. As a compliance alternative to maintaining a flow rate at or below 3 scfm, the EPA is proposing that an owner or operator of a centrifugal compressor equipped with wet seals can comply with EG OOOOc by reducing methane emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent, which achieves emission reductions greater than or equal to the 3 scfm proposed presumptive standard. Options to meet this emission reduction requirement include routing emissions via a CVS to a control device or to the process. This standard can also be met by an owner or operator utilizing a self-contained wet seal centrifugal compressor. The same requirements specified in IV.G.1.c for wet seal compressors complying with the requirements to reduce methane emissions from each centrifugal compressor wet seal fluid degassing system by 95 percent are being proposed for wet seal compressors complying with this option under EG OOOOc.

H. Combustion Control Devices

1. November 2021 Proposal

The EPA proposed requiring 95 percent methane and VOC reduction for certain affected/designated facilities (*i.e.,* storage vessels, wet seal centrifugal compressors, and associated gas from oil wells when a sales line is not available) and solicited comments on several aspects of the operational efficiency of combustion control devices and methods to ensure continuous compliance with the required control efficiency. Specifically, in the November 2021 proposal, the EPA solicited comments on whether additional measures to ensure proper performance of flares would be appropriate to ensure that flares meet the current 95 percent control requirement. The EPA solicited similar comments for enclosed combustion devices, particularly regarding creating comprehensive specifications for an operating envelope under which a make/model can achieve 98 percent reduction. The EPA also solicited comments on the practicality of requiring combustion and non-combustion control systems to meet a 98 percent reduction control requirement under operating conditions present in the oil and gas industry. Finally, the EPA solicited comment on new technologies that would provide real-time or near real-time measurement of control efficiency, particularly for flares.

2. Changes From November 2021 Proposal

The EPA received comments on most aspects of the solicitation for comments in the November 2021 proposal related to combustion control devices, ranging from opposition to requirements as specific as continuous pilots to recommendations for the use of advanced technologies to continuously monitor flare combustion efficiency. As described throughout this section, the EPA is proposing specific additional requirements in response to comments on the November 2021 proposal and clarifying other requirements that were proposed in that action.

In this supplemental proposal, the EPA is proposing requirements for various combustion control devices to develop consistent monitoring, recordkeeping, and reporting requirements, regardless of the affected/designated facility with which the control device is associated. This is different than the compliance requirements for control devices in NSPS OOOOa, which has separate requirements for control devices used on storage vessel affected facilities, than those used on centrifugal compressor affected facilities. The proposed monitoring, recordkeeping, and reporting requirements related to control devices are designed to ensure that these systems achieve the required control efficiency, and they were established using methods that limit the burden for owners and operators, while still ensuring compliance with the required control efficiency.

Flares. The EPA is proposing to include in both NSPS OOOOb and EG OOOOc more comprehensive monitoring requirements for flares as referenced to the General Provisions at 40 CFR 60.18. Specifically, the General Provisions at 40 CFR 60.18 indicate four criteria needed for good flare performance. These are: (1) Continuous pilot flame; (2) no visible emissions except for a total of 5 minutes in a 2-

hour period; (3) minimum net heating value of gas sent to the flare; and (4) maximum flare tip velocity. In NSPS OOOO and NSPS OOOOa, the compliance requirements for flares include criteria to address compliance with items 1 and 2 but do not include any requirements that would ensure compliance with items 3 and 4 for any affected facilities which reference flares as a control device option. That is, those rules, which adopt by reference the flare requirements in 40 CFR 60.18 (*i.e.,* the General Provisions to 40 CFR part 60) do not include specific requirements specifying the minimum net heating value of gas sent to the flare or the maximum flare tip velocity. One commenter on the November 2021 proposal stated that the EPA must establish continuous monitoring requirements for flares regardless of the control efficiency required.[200] One commenter noted that the General Provisions at 40 CFR 60.18 state that the referencing subpart will specify the monitoring requirements and indicated that the EPA must specify these requirements in the new standards.[201] The EPA agrees with these commenters, especially noting that recent studies suggests that 10 percent of flares in the Permian basin are either unlit or are only burning a portion of the gas sent to the flare.[202] Consequently, the EPA concludes that the current operating and monitoring practices and requirements for well sites and centralized production facilities are not adequate to ensure flare control systems are operated efficiently and is therefore, proposing compliance requirements to ensure all aspects of the General Provisions at 40 CFR 60.18 are met at all times. These include requirements to ensure a pilot flame is present at all times through monitoring with a device such as a thermocouple, ultraviolet beam sensor, or infrared sensor and monitoring of NHV through use of a calorimeter, unless a demonstration has been made that the NHV of the inlet gas to the flare consistently exceeds the operating limit established in the rule. In other rulemakings, for example recent amendments to the refining [203] and chemical sector [204] rules, monitoring of the net heating value in the combustion zone, instead of the heating value of the vent gas is required. While this is important for an assisted flare, we anticipate the oil and gas source category predominately will use unassisted flares, because air-assisted flares require electricity and not all sites will have access to electricity. The EPA finds that the provisions at 40 CFR 60.18 are sufficient for unassisted flares because the heat content of the gas at the flame is not diluted by an assist stream of gas or air. The EPA requests comment on the universe of unassisted and assisted flares in the oil and gas sector. See section IV.H.3 of this preamble for details of the proposed compliance requirements for flares.

Enclosed Combustors. The EPA is proposing the same monitoring requirements for enclosed combustion devices for all affected facilities that use such devices to meet the applicable standards. We are also proposing monitoring requirements for enclosed combustion devices (which are not tested by the manufacturer) for which the performance test does not correlate the combustion efficiency achieved by the combustion device with temperature. (*i.e.,* temperature is not well correlated with combustion efficiency). NSPS OOOO and OOOOa have separate monitoring requirements for control devices used for centrifugal compressor affected facilities than for control devices used for storage vessel affected facilities. This difference goes back to the EPA's understanding of the landscape of the oil and gas industry during the rulemaking process for NSPS OOOO and subsequent amendments through 2016 which resulted in the promulgation of NSPS OOOOa. Centralized production facilities were not identified within the EPA's emissions inventory, and the EPA found that storage vessels were mostly located at well sites which did not have other affected facilities requiring control. The EPA expected these sites to take advantage of the reduced compliance burden by using control devices tested by the manufacturer. Further, during the reconsideration of aspects of NSPS OOOO, the EPA determined that streamlined compliance options were warranted for storage vessel affected facilities, in part because of implementation issues at remote sites and the large number of storage vessel affected facilities.[205] In this action, the EPA is proposing standards for additional affected facilities at well sites (*i.e.,* oil wells with associated gas that is routed to a control device) and defining centralized production facilities (which include storage vessel and compressor affected facilities requiring 95 percent control). The EPA finds that the rationale used in NSPS OOOO and NSPS OOOOa supporting streamlined monitoring for storage vessels no longer holds true. Remote well sites still exist, but these sites also may be subject to standards for oil well with associated gas and the compliance burden is shared between those affected facilities to ensure emissions from both storage vessels and oil wells with associated gas are reduced by 95 percent. Further, the centralization of production activities makes moot the concern about remote wells sites for these centralized production facilities. As mentioned previously, recent studies such as the study conducted in the Permian, indicate pervasive issues with combustion sources [206] and enforcement activities conducted by the EPA and states have uncovered issues with proper operation of enclosed combustors on storage vessels.[207] For these reasons, the EPA is proposing to align the monitoring requirements in NSPS OOOOb and EG OOOOc to ensure that all control devices are subject to the same monitoring requirements, regardless of the affected facility being controlled.

For thermal oxidizers/enclosed combustors for which temperature is correlated with combustion efficiency and for catalytic oxidizers, the EPA is proposing to include in NSPS OOOOb and EG OOOOc the same monitoring requirements as required under NSPS OOOOa for centrifugal compressor affected facilities, and consistent with the rationale in this discussion, we are proposing to require these monitoring requirements for all enclosed combustion devices, regardless of the affected facility being controlled. Further, the EPA is proposing additional initial compliance requirements for vapor recovery devices and catalytic vapor incinerators, to ensure owners and operators have a clear roadmap for initial compliance. Similarly, the EPA is proposing additional continuous compliance requirements which specify how to determine continuous compliance with the requirements for

[200] See Document ID Nos. EPA–HQ–OAR–2021–0317–0844 and EPA–HQ–OAR–2021–0317–1282.

[201] See Document ID No. EPA–HQ–OAR–2021–0317–1282.

[202] Permian Methane Analysis Project (PermianMAP) reporting the results of 4 Environmental Defense Fund (EDF) surveys of over a thousand flare stacks from February to November 2020. See *https://www.permianmap.org/flaring-emissions.*

[203] See 80 FR 75266 (December 1, 2015).

[204] See 85 FR 49132 (August 12, 2020).

[205] See 78 FR 58438 (September 23, 2013) and 81 FR 35897 (June 3, 2016).

[206] Permian Methane Analysis Project (PermianMAP) reporting the results of 4 Environmental Defense Fund (EDF) surveys of over a thousand flare stacks from February to November 2020. See *https://www.permianmap.org/flaring-emissions.*

[207] ''EPA Observes Emissions from Controlled Storage Vessels at Onshore Oil and Gas Production Facilities.'' See *https://www.epa.gov/sites/default/files/2015-09/documents/oilgascompliancealert.pdf.*

catalytic vapor incinerators, regenerative-type carbon adsorption systems, and carbon management for regenerative-type and nonregenerative-type carbon adsorption systems.

The EPA is also proposing monitoring requirements for enclosed combustion devices not tested by a manufacturer for which temperature is not well correlated with combustion efficiency. For enclosed combustors for which temperature is not well correlated with combustion efficiency, the EPA is proposing to incorporate requirements similar to those proposed for flares, as the operation of these devices is similar to the operation of a flare in that the combustibility of the gas (NHV), operation without smoking (visible emissions) and a continuous burning pilot flame are fundamental to ensuring 95 percent combustion. One commenter suggested that monitoring of the pilot flame for enclosed combustors was sufficient to provide assurance of effective emission control.[208] However, no data were provided to support this assertion and available data and combustion theory science suggests that the net heating value of the gas being sent to the combustor is also critical to ensure proper combustion. As good combustion depends upon the fuel having a minimum amount of heat content, if the gases from the affected facility required to be controlled have low heat content at times, then auxiliary fuel may be necessary to ensure good combustion during those periods. That is, the same requirements that are needed to ensure proper performance of flares also apply to enclosed combustors. Because enclosed combustors often are associated with storage vessels which have variable emissions events depending on working, breathing, standing, or flashing losses, the EPA also is proposing that enclosed combustors monitor inlet flow rate to ensure the control device operates within the compliance envelope at which compliance with the 95 percent control efficiency was demonstrated.

Condensers and Carbon Adsorption Systems. The EPA is proposing consistent monitoring requirements for condensers and carbon adsorption systems independent of the affected facility. NSPS OOOOa has specific compliance requirements for condensers and carbon adsorption systems used to control emissions from centrifugal compressor affected facilities but less specific compliance requirements for vapor recovery devices used for storage vessel affected facilities. In NSPS OOOOa, owners and operators are required to conduct specific parameter monitoring for condensers and carbon adsorption systems used to control emissions from centrifugal compressor affected facilities, while owners and operators are only required to conduct monthly inspections ''. . . to ensure physical integrity of the control device according to the manufacturer's instructions'' for vapor recovery devices used to control storage vessel affected facilities. Monthly inspections do not ensure the condenser temperature is adequate or that the carbon beds are changed out or regenerated at a frequency to ensure the control device is achieving at least 95 percent control efficiency. Therefore, in NSPS OOOOb and EG OOOOc, the EPA is proposing that all affected and designated facilities that use condensers or carbon adsorption systems must meet the same monitoring requirements as outlined for centrifugal compressor affected facilities in NSPS OOOOa.

Manufacturer Tested Control Devices. The EPA is proposing to require the same initial requirements for manufacturer testing of control devices and ancillary monitoring requirements as required in NSPS OOOO and NSPS OOOOa. In NSPS OOOO and NSPS OOOOa, the EPA included this alternative to minimize issues associated with performance testing of certain combustion control devices in the field. The requirements were based on similar requirements in the oil and natural gas NESHAP (40 CFR part 63, subparts HH and HHH) and which had been successfully implemented for some time prior to the promulgation of NSPS OOOO and NSPS OOOOa. In the 2011 proposal of the provisions for NSPS OOOO, we stated ''[w]e believe that testing units that are not configured with a distinct combustion chamber present several technical issues that are more optimally addressed through manufacturer testing, and once these units are installed at a facility, through periodic inspection and maintenance in accordance with manufacturers' recommendations. One issue is that an extension above certain existing combustion control device enclosures will be necessary to get adequate clearance above the flame zone. Such extensions can more easily be configured by the manufacturer of the control device rather than having to modify an extension in the field to fit devices at every site. Issues related to transporting, installing and supporting the extension in the field are also eliminated through manufacturer testing. Another concern is that the pitot tube used to measure flow can be altered by radiant heat from the flame such that gas flow rates are not accurate. This issue is best overcome by having the manufacturer select and use the pitot tube best suited to their specific unit. For these reasons, we believe the manufacturers' test is appropriate for these control devices with ongoing performance ensured by periodic inspection and maintenance. (76 FR 52785; August 23, 2011).

Control Efficiency. As mentioned earlier in this section, the EPA requested comment on whether the EPA should require 98 percent reduction of methane and VOC emissions instead of 95 percent in the November 2021 proposal. The EPA received comments stating that flares can be designed to meet 98 percent control efficiency,[209] but we also received comments stating that variability in gas flow, pressure, and quality would present challenges to achieving 98 percent control efficiency, especially at low production wells.[210]

The EPA evaluated the costs associated with requiring 98 percent reduction of methane and VOC emissions from storage vessels in order to compare the cost-effectiveness for this option against the costs associated with requiring 95 percent reduction. While the analysis was specific for storage vessels, the conclusions drawn from this analysis are generally applicable to other affected facilities because the size range of control devices evaluated cover the range of controls used for other affected facilities. Based on this evaluation, we conclude that the additional reduction is not cost effective and would therefore not represent the BSER for affected sources requiring an emissions reduction through the use of a pollution control device. Specifically, using this example for storage vessel affected facilities, the EPA added the additional monitoring and operational costs expected to ensure a 98 percent minimum destruction efficiency and found that it would not be cost-effective to require control of storage vessels with the potential for VOC emissions below 12 tpy or methane emissions below 40 tpy. However, at 95 percent reduction, it is considered cost-effective to require control of storage vessels with potential VOC emissions of 6 tpy and methane

[208] See Document ID No. EPA–HQ–OAR–2021–0317–0749.

[209] See Document ID Nos. EPA–HQ–OAR–2021–0317–0604, EPA–HQ–OAR–2021–0317–0605, EPA–HQ–OAR–2021–0317–0844, and EPA–HQ–OAR–2021–0317–1286.

[210] See Document ID Nos. EPA–HQ–OAR–2021–0317–0599, EPA–HQ–OAR–2021–0317–0808, and EPA–HQ–OAR–2021–0317–0831.

emissions of 20 tpy.[211] Therefore, requiring 98 percent reduction of methane and VOC results in the control of fewer storage vessels, and thus result in fewer overall emissions reductions. Consequently, the EPA is proposing to maintain that the BSER for storage vessel affected facilities is 95 percent reduction, as described in section IV.J of this preamble. Because the analysis conducted covers the range of control device sizes utilized by other affected facilities, similar impacts on the BSER analysis are expected. Furthermore, because individual sites would utilize a single control device for all affected/designated facilities, it does not make sense to require different emissions reduction standards for different affected/designated facilities. For more detail on the analysis conducted to assess the costs of control device monitoring see memorandum Analysis of Monitoring Costs to Ensure 98 Percent Destruction Efficiency, available in the docket for this action (Docket ID No. EPA–HQ–OAR–2021–0317).

3. Summary of Proposed Requirements for NSPS OOOOb and EG OOOOc

The EPA is proposing that control devices used for any affected facility must demonstrate that they meet a 95 percent VOC and methane emission reduction requirement through a performance test (or for condensers and carbon absorbers, through a design evaluation) or manufacturer's performance test.

In NSPS OOOOb and EG OOOOc, we are proposing the same control device requirements for thermal vapor incinerators (including thermal oxidizers and enclosed combustors) for which temperature is correlated with destruction efficiency, catalytic vapor incinerators, condensers, and carbon adsorption systems as were required in NSPS OOOOa (for centrifugal compressor affected facilities). We are proposing that these requirements apply to all affected facilities complying with the standards by using one of these control devices.

The EPA is proposing requirements for flares to be designed and operated according to the provisions in 40 CFR 60.18 for all flares, regardless of the affected facility type, except as noted below for pressure-assisted devices. Further, we are proposing to require these same general requirements for enclosed combustors not tested by the manufacturer and for which temperature is not correlated with control device performance. NSPS OOOO and NSPS OOOOa do not include criteria to determine that temperature is (or is not) correlated with control device performance. Criteria where temperature is well correlated could include requirements that air flow to the burner is controlled and that there is sufficient refractory in the stack to maintain high temperature even at low flows. The EPA requests comment on whether criteria should be developed for NSPS OOOOb and EG OOOOc, which delineate when temperature is (or is not) correlated with control device performance, and if so, in addition to the criteria above, what criteria would be appropriate. The EPA is proposing to include consistent initial and continuous compliance requirements to ensure flares and enclosed combustion devices are maintaining efficient combustion. As discussed previously in this section, there are 4 critical requirements in 40 CFR 60.18 that must be met to ensure proper destruction efficiency.[212] The proposed continuous compliance requirements for each of these critical elements are described in the following paragraphs.

First, the EPA is proposing to require all flares and enclosed combustion devices[213] to have a continuous pilot flame and install a continuous parameter monitoring system capable of continuously (at least once every 5 minutes) monitoring for the presence of a pilot or combustion flame. This is in keeping with the requirements of the General Provisions to require a continuous pilot flame. The EPA is specifying more frequent monitoring intervals for the pilot light than for other continuous parameter monitoring systems (which require a minimum of one reading per hour) because the destruction efficiency will rapidly fall to zero in the absence of a pilot or combustion flame. Therefore, we determined that more frequent readings were needed for the pilot flame monitoring system to ensure the flare or enclosed combustion device achieves 95 percent destruction efficiency at all times.

Second, the EPA is proposing to require inspections to monitor for visible emissions using section 11 of EPA Method 22 of appendix A–7 of part 60 (EPA Method 22). The observation period for the EPA Method 22 inspection would be 15 minutes. Visible emissions longer than 1 minute during the 15-minute period would be a deviation of the standard. This is consistent with similar requirements in NSPS OOOOa. The EPA is proposing that these inspections would occur monthly, and at other times as requested by the Administrator. For example, if the Administrator observed a flare with intermittent visible emissions, the Administrator may require the owner or operator to conduct an EPA Method 22 inspection to determine whether the flare is exceeding the visible emissions limit.

Next, the EPA is proposing that flares and enclosed combustion devices monitor the net heating value of the vent gas sent to the flare or combustor. Owners and operators would install a continuous parameter monitoring system, such as a calorimeter, to continuously determine the net heating value of the gas sent to the flare or combustor. Alternatively, the owner or operator could conduct an initial assessment to demonstrate that the net heating value of the vent gas sent to the flare or combustor consistently exceeds the required minimum net heating value in 40 CFR 60.18 or the minimum net heating value proposed for pressure-assisted flares.[214] The proposed initial demonstration consists of hourly monitoring over 10 days. The EPA is proposing this frequency and duration of monitoring in order to provide a large sampling set by which to assess the variability of the vent gas sent to the combustion device and to adequately characterize the tails of the distribution. When actively controlling net heating value, operators will generally control at a set point 10 to 20 percent higher than the limit to ensure they are meeting the limit at all times. Therefore, the EPA concluded that a 20 percent cushion was a reasonable minimum value for ''well above the threshold.'' To be considered consistently above the net heating value threshold, greater than 90 percent of the measurements would need to be ''well above the threshold,'' with no readings below the threshold. Based on these considerations, the EPA

[211] The costs associated with the monitoring requirements necessary to ensure a 95 percent reduction in methane and VOC emissions is achieved were included in the cost analysis provided in the November 2021 proposal. See the 2021 TSD for additional details at Document ID No. EPA–HQ–OAR–2021–0317–0166 and accompanying spreadsheets at Document ID No. EPA–HQ–OAR–2021–0317–0039.

[212] The four requirements are: (1) Continuous pilot flame; (2) no visible emissions except for a total of 5 minutes in a 2-hour period; (3) minimum net heating value of gas sent to the flare; and (4) maximum flare tip velocity.

[213] This discussion in the rest of this section applies to those enclosed combustion devices for which temperature is not correlated with destruction efficiency.

[214] Pressure-assisted devices are not required to comply with the vent gas net heating value in 40 CFR 60.18. The EPA is proposing alternative net heating value requirements for these devices as discussed in detail below.

is proposing that if there are no hourly gas samples with a net heating value below the required minimum net heating value and 20 or fewer hourly gas samples are less than 1.2 times the required minimum net heating value, then the gas stream is considered to be ''consistently above the threshold'' and on-going continuous monitoring is not required.

Lastly, to ensure compliance with the maximum flare tip velocity requirement in 40 CFR 60.18, for flares and enclosed combustion devices, the EPA is proposing to require installation of a continuous parameter monitoring system to determine the flow of gas sent to the flare or combustor, except as noted below for pressure-assisted devices. Alternatively, the owner or operator may conduct an initial engineering assessment of the sources vented to the flare to demonstrate that, based on the maximum pressure of these sources, the maximum possible gas flow rate would not exceed the allowed maximum flare tip velocity in 40 CFR 60.18 or the maximum design flow rate of the enclosed combustor.

The EPA has also determined that combustion devices may be operating at gas flow rates that are too low to support efficient combustion, resulting in uncombusted vented emissions. To address this issue, the EPA is proposing to require that manufacturers establish both a minimum and maximum flow rate during the testing performed under 40 CFR 60.5413b(d) and 40 CFR 60.5413c(d) to ensure these devices operate efficiently in the field. Combustion control devices previously tested by the manufacturer for which the manufacturer was able to demonstrate the control device meets the performance requirements would not need to perform new performance tests. The zero-level at which the combustion control device was tested will be extracted from the previously submitted performance test report and added to the information on the EPA's website.[215] For flares and enclosed combustion devices not tested by the manufacturer under 40 CFR 60.5413b(d) or 40 CFR 60.5413c(d), the owner or operator would be required to establish a minimum vent gas flow rate based on manufacturer recommendations. Owners and operators would be required to continuously monitor the vent gas flow rate to ensure that it is above this minimum level whenever vent gas is sent to the flare or enclosed combustion device. As an option, the owner or operator could install a backpressure preventer which is set to operate at or above the minimum inlet gas flow rate. The EPA is soliciting comment on this additional requirement and whether there are additional situations where continuous monitoring of the vent gas flow rate is unnecessary.

For pressure-assisted devices, the EPA is proposing to include special provisions in NSPS OOOOb/EG OOOOc, which include a minimum net heating value (NHV) of the gas sent to the flare/combustor of 800 British thermal units per standard cubic feet (Btu/scf) and an exemption from the maximum velocity requirements in 40 CFR 60.18.[216] Pressure-assisted devices are designed to operate at high flare or burner tip velocities and use this velocity to improve mixing of the flared gas with surrounding air. For good combustion efficiency at these high velocities, the flared gas must have higher heat content than a non-pressure-assisted flare. The EPA evaluated pressure-assisted flares and determined that these flares must have flare gas with an NHV of 800 Btu/scf or higher to work efficiently.[217 218] Also, because the burners are specifically designed to have high flow rates, the burner tip velocity typically exceeds the maximum flare tip velocity limit in 40 CFR 60.18. The maximum velocity limits in 40 CFR 60.18 were set to prevent flame ''lift off'' or flame instability from conventional flare tips. However, pressure-assisted flare tips are specifically designed to operate efficiently at much higher velocities. The EPA found that pressure assisted flares can operate efficiently at these higher velocities. Therefore, the EPA is proposing that pressure-assisted devices would not be subject to the maximum flare tip velocity limit.

Finally, the EPA is proposing operating requirements at 40 CFR 60.5417b(f) (and 40 CFR 60.5417c(f)) and specifying what constitutes a deviation at 40 CFR 60.5417b(g) (and 40 CFR 60.5417c(g)) that are consistent with the operating and monitoring requirements outlined in this section and that are consistent across all affected facilities using control devices. Further, these sections are referenced in the recordkeeping and reporting requirements for each affected facility so that the reporting requirements for affected facilities that use control devices to comply with the standard have consistent control device reporting requirements regardless of the type of affected facility. The EPA is soliciting comment on all proposed requirements for control devices described within this section.

I. Reciprocating Compressors

In a reciprocating compressor, natural gas enters the suction manifold and then flows into a compression cylinder, where it is compressed by a piston driven in a reciprocating motion by the crankshaft, which is powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn, and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder.

1. NSPS OOOOb

a. November 2021 Proposal

Based on the analysis presented in section XII.E.1 of the November 2021 proposal preamble (86 FR 63214–63220; November 15, 2021), the proposed BSER for NSPS OOOOb for reducing GHGs and VOC from new reciprocating compressors was the replacement of the rod packing based on an annual monitoring threshold. Under the November 2021 proposal, the owner or operator of a reciprocating compressor affected facility would have been required to monitor the rod packing emissions annually by conducting flow rate measurements. When the measured flow rate exceeded 2 scfm (in pressurized mode), replacement of the rod packing would have been required. As indicated at proposal, the 2 scfm flow rate threshold was established based on manufacturer guidelines indicating that a flow rate of 2 scfm or greater was considered indicative of rod packing failure.[219] Alternatively, the November 2021 proposal would have

[215] Information on combustion control devices tested by the manufacturer can be found at: *https://www.epa.gov/stationary-sources-air-pollution/performance-testing-combustion-control-devices-manufacturers.*

[216] Pressure-assisted devices would still be subject to the requirements for a continuous pilot flame and the visible emissions requirement, as well as the requirement to continuously monitor (or perform an assessment) on the NHV of the vent gas.

[217] ''Notice of Final Approval for the Operation of a Pressure-Assisted Multi-Point Ground Flare at Occidental Chemical Corporation,'' 81 FR 23480, April 21, 2016, and ''Notice of Final Approval for an Alternative Means of Emission Limitation at ExxonMobil Corporation; Marathon Petroleum Company, LP (for Itself and on Behalf of Its Subsidiary, Blanchard Refining, LLC); Chalmette Refining, LLC; and LACC, LLC,'' 83 FR 46939, September 17, 2018.

[218] Because pressure-assisted flares generally do not use assist gas, combustion zone NHV is the same as the flare gas NHV.

[219] 86 FR 63218 (November 15, 2021).

also provided owners and operators the option of routing rod packing emissions to a process via a CVS under negative pressure in order to comply with the rule. The proposed option to route to a process is allowed as an alternative under NSPS OOOOa because implementing this option, where feasible, would achieve greater emission reductions than the primary fixed schedule rod packing replacement BSER requirement under NSPS OOOOa.

b. Changes From November 2021 Proposal

The BSER analysis is unchanged from what was presented in the November 2021 proposal (see 86 FR 63214–63220, section XII.E. Reciprocating Compressors). The EPA is proposing changes and specific clarifications to the November 2021 proposal standards for NSPS OOOOb. For the proposed replacement of the rod packing based on an emission limit and annual measurement requirement, we are proposing: (1) To clarify that the standard of performance is a numeric standard (not a work practice standard) of 2 scfm, (2) to allow for repair (in addition to replacement) of the rod packing in order to maintain an emission rate at or below 2 scfm; (3) to allow for monitoring based on 8,760 hours of operation instead of based on a calendar year. We are also proposing regulatory text that clearly defines the required flow rate measurement methods and/or procedures, repair and replacement requirements, and recordkeeping and reporting requirements. For the alternative option of routing rod packing emissions to a process via a CVS under negative pressure, we are proposing to remove the negative pressure requirement. These changes take into account comments received on the November 2021 proposal, as explained below.

The basis for the proposed changes and clarifications to the replacement of the rod packing based on a flow rate monitoring measurement for reciprocating compressors is presented in section IV.I.1.b.i of this preamble. The basis for the proposed change to the alternative option of routing rod packing emissions to a process via a CVS under negative pressure is presented in section IV.I.1.b.ii of this preamble. A summary of the proposed reciprocating compressor standards is presented in section IV.I.1.b.iii of this preamble.

i. Numerical Emission Limit Standard Proposed Changes

Changes to Format of the Standard. In re-considering the BSER determination and standards for reciprocating compressors proposed in November 2021, the EPA recognized that it is feasible to prescribe a standard of performance, rather than a work practice standard,[220] for reciprocating compressors. Accordingly, the EPA is now proposing a numerical emission limit requirement. The major difference between this standard and what the EPA proposed in November 2021 is that under this supplemental proposal, owners and operators would be required to maintain emissions at or below the emission limit (emission flow rate of 2 scfm) whereas under the November proposal, owners or operators would have been required to change out the rod packing only after discovering an exceedance of 2 scfm. The BSER is replacement of the rod packing and/or other necessary repair and maintenance activities to maintain emissions at or below 2 scfm.

Repair or Replacement. Commenters on the November 2021 proposal urged the EPA to allow for repair as an alternative to complete replacement of rod packing. The commenters pointed out that allowing repair would be consistent with California's reciprocating compressor rule requirements. See 17 California Code of Regulation section 95668(c)(3)(D).[221] One commenter noted that, for older units, replacing the rod packing does not always address emissions levels, as other maintenance issues can contribute to cylinder emissions, such as issues with the rod itself. The commenter added that providing the flexibility to repair as well as replace the rod packing could significantly impact personnel costs—while rod packing replacement on older units can require approximately 32-man hours per cylinder, a repair may entail a significantly lower level of effort and hours of labor.[222]

The EPA agrees with the commenters' suggestion. The intent of the proposed reciprocating compressor standard was to require that the volumetric flow rate be maintained at or below 2 scfm. If repair can maintain the volumetric flowrate at or below 2 scfm without the need to replace the rod packing, the intent of the proposed standards would be met. Thus, under the proposed numerical emission limit, an owner or operator would be allowed to repair or replace the rod packing in order to maintain the volumetric flow rate at or below the 2 scfm emission limit.

Hours of Operation Versus Calendar Year. Commenters [223] on the November 2021 proposal recommended that the EPA consider requiring flow rate monitoring based on a compressor's hours of operation totaling one year (*i.e.,* 8,760 hours) in lieu of requiring annual flow rate measurements based on a calendar year. Commenters stated that using the compressor's hours of operation would ensure that undue burden is not placed on owners and operators where compressors are not operational for multiple months or are used intermittently. The commenters explained that basing flow rate measurement requirements on a reciprocating compressor's hours of operation would allow owners and operators to stagger maintenance activity throughout the year. The comments further suggested that the EPA consider exemptions from the rule for limited-use reciprocating compressors and changing the flow rate measurement monitoring requirement frequency to every 2 years.

In order to address limited-use reciprocating compressors and to allow owners and operators flexibility when planning maintenance, the EPA agrees that it makes sense to require periodic reciprocating compressor flow rate monitoring based on the hours of operation (*i.e.,* 8,760 hours) in lieu of requiring monitoring based on a calendar year. Thus, we are proposing to allow for periodic flow rate monitoring based on 8,760 hours of operation instead of requiring monitoring on a calendar year basis.

Regulation Clarifications. Several commenters [224] requested that the EPA clearly state in the rule that the GHGRP subpart W methods be allowed for the flow rate measurements. These commenters also requested that the EPA clearly state the proposed reciprocating compressor annual monitoring threshold and the repair and rod packing replacement requirements. Specifically, they sought certainty

[220] Under CAA section 111(h)(1), work practice standards are appropriate only where "it is not feasible to prescribe or enforce a standard of performance." CAA section 111(h)(2) defines such infeasibility as "any situation in which the Administrator determines that (A) a pollutant 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 sources is not practicable due to technological or economic limitations."

[221] Final Regulation Order. California Code of Regulations, *Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4. Subarticle 13: Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.*

[222] See Document ID No. EPA–HQ–OAR–2021–0317–0817.

[223] See Document ID No. EPA–HQ–OAR–2021–0317–0415.

[224] See Document ID Nos. EPA–HQ–OAR–2021–0317–0415, and EPA–HQ–OAR–2021–0317–1375.

regarding the schedule for repair and ''delay of repair'' criteria to ensure unnecessary restrictions are not placed on repair schedules, and a clear explanation of operating requirements for measurement (*i.e.,* when the unit is operating).

The EPA considered the commenters' specific requests for clarity within the requirements when developing the proposed regulatory text and the desire to be consistent with the GHGRP subpart W. We recognize this desire however we are concerned the flow rate measurements methods under GHGRP subpart W are not as well-defined or prescriptive as the methods the EPA requires for demonstrating compliance with an emission standard. Instead, the EPA is proposing the use of volumetric flow rate which meet the requirements of Method 2D (40 CFR part 60, appendix A) for testing emissions from reciprocating compressor rod packing and the use of a high-volume sampler to measure the emissions from proposing either the reciprocating compressor rod packing or centrifugal compressor seal vents (dry seals for NSPS OOOOb and all centrifugal compressor wet and dry seals for EG OOOOc).[225] For the high-volume sampler, instead of relying on manufacturer defined procedures required in GHGRP Subpart W, the EPA is proposing a defined set of procedures and performance objectives to ensure consistent application of these samplers. In an effort to allow for additional innovation for these types of measurements, the EPA is also proposing to allow other methods, subject to Administrator approval, that have been validated according to Method 301 (40 CFR part 63, appendix A). The EPA solicits comment on the use of the proposed performance test methods and solicits comment on other methodologies that could be used to demonstrate compliance with the centrifugal compressor dry seal vent, centrifugal compressors for EG OOOOc, and reciprocating compressor rod packing emission standards.

The proposed NSPS OOOOb regulatory text also specifies that flow rate monitoring be conducted in operating or standby pressurized mode, and ''repair'' and ''delay of repair'' schedules, in addition to other clarifying requirements. The EPA is proposing to require conducting flow rate measurements during operating or standby pressurized mode because the measured emissions would be representative of actual emissions during operations. Repair schedules are proposed to require repair of equipment in a timely manner to mitigate emissions. Delay of repair would be allowed when owners and operators required more time to repair equipment based on scenarios beyond the owner or operator's control (*e.g.,* issues with availability of equipment or where repair necessitates a compressor shutdown when redundancy of compressors is not available).

ii. Routing Emissions to a Process Via a Closed Vent System Under Negative Pressure

The EPA received comments on the November 2021 proposal related to its proposed compliance alternative of routing rod packing emissions to a process via a CVS under negative pressure. One commenter[226] noted that routing emissions to a process should not require negative pressure, stating that some pressure differential is required to take gas out of the rod packing vent and into the desired location. This commenter further stated that the use of negative pressure can raise safety and operational issues, and that operating a crankcase collection system under negative pressure (*i.e.,* in a vacuum) creates the possibility of introducing oxygen into the system. This commenter added that allowing for pressure differential without requiring operation under negative pressure could lead to larger emission reductions overall, and that the proposed negative pressure requirement eliminates the ability to use technologies that could reduce emissions further. Another commenter[227] similarly reported that the use of negative pressure presents safety concerns of creating an explosive mixture of natural gas and atmospheric air, should there be any leak between the negative pressure source and the packing vent. The commenter stated that as long as the packing vent recovery system is at a lower pressure; the packing vent gas will be recovered without leaking to atmosphere and there will be no risk of introducing atmospheric air to the natural gas.

The November 2021 proposal included the requirement to route rod packing emissions to a process via a CVS under negative pressure based on information submitted by a petitioner[228] on NSPS OOOO that requested/suggested an alternative standard that would result in equal to or greater emissions reductions than the rod packing replacement standard. The petitioner's suggested alternative standard was to capture emissions under negative pressure, thus allowing all emissions to be routed to the engine. The petitioner suggested achieving this by recovering vented emissions from the rod packing under negative pressure and routing these emissions of otherwise vented gas to the air intake of a reciprocating internal combustion engine that would burn the gas as fuel to augment the normal fuel supply. The petitioner reasoned that emission reductions would be commensurate with, or better than, the reductions from the rod packing replacement standard. The EPA acknowledged at the time (2014) that this technology may not be applicable or feasible for every compressor installation and situation. However, the EPA proposed this option as an alternative to the rod packing replacement standards for those instances where it could be applied.[229]

In light of the comments received on the November 2021 proposal, and an increased understanding of this type of approach, the EPA is proposing to revise the compliance alternative by continuing to allow emissions to be routed to a process via a CVS but removing the requirement for this to occur under negative pressure. The intent of requiring ''negative pressure'' was that there be sufficient pressure differential such that emissions would be routed from the compressor via the CVS to the process. The EPA did not intend to create a safety issue or limit technologies that would achieve equivalent or greater emission reductions than the work practice standard. Since such a pressure differential would be created when the reciprocating compressor is operating, specifying that emissions need to be routed to a process via a CVS under negative pressure is unnecessary. As the commenter noted, this is already understood for other sources where the standards require routing of emissions through a CVS to a process or control device.

As noted above, routing emissions to a process is an existing compliance option under NSPS OOOO and NSPS OOOOa and the EPA has assumed that the emissions reduced by this option, where feasible to implement, are greater than those achieved by the proposed BSER requirement to implement maintenance and repair activities to maintain the flow rate (as a surrogate for emissions) from the reciprocating compressor rod packing at or below 2

[225] See section IV.G. for discussion on centrifugal compressors.

[226] See Document ID No. EPA–HQ–OAR–2021–0317–0817.

[227] See Document ID No. EPA–HQ–OAR–2021–0317–0745.

[228] Letter from Veronica Nasser, REM Technologies, Inc., to Lisa P. Jackson, EPA Administrator, Petition for Reconsideration.

[229] See 79 FR 41760–41761 (July 17, 2014).

scfm. The EPA solicits comment on its assumption that the emissions reduced by requiring the capture of gas and routing to a process are greater than the requirement to maintain the flow rate from the reciprocating compressor rod packing at or below 2 scfm. The EPA also is soliciting comment on the prevalence of owners and operators complying with NSPS OOOO and NSPS OOOOa by capturing and routing emissions from the reciprocating compressor rod packing to a process.

iii. Summary of Proposed Standards

Affected Facility. The EPA is proposing to define a reciprocating compressor affected facility as each reciprocating compressor, which is a single reciprocating compressor. A reciprocating compressor located at a well site is not an affected facility under this subpart. A reciprocating compressor located at a centralized production facility is an affected facility under this subpart.

Numerical Emission Limit Standards. The proposed NSPS OOOOb standard of performance for reciprocating compressor affected facilities is a numerical emission limit of 2 scfm (in operating or standby pressurized mode). The volumetric flow rate measurement from each reciprocating rod packing must be maintained to be less than or equal to a flow rate of 2 scfm (in operating or standby pressurized mode). The proposed BSER is to repair or replace the rod packing and to conduct other necessary repair and maintenance in order to maintain the emission rate at or below 2 scfm. The proposed monitoring requirements are to conduct volumetric flow rate measurements from each reciprocating compressor rod packing using the proposed monitoring methods in 40 CFR 60.5386b (which includes similar screening and flow rate measurement methods as required under GHGRP subpart W).

The EPA is proposing to require the first volumetric flow rate measurements from a reciprocating compressor affected facility on or before 8,760 hours of operation. Subsequent volumetric emissions measurements from a reciprocating compressor affected facility would be required on or before 8,760 hours of operation after the previous measurement, or on or before 8,760 hours of operation after the date of the most recent reciprocating compressor rod packing replacement, whichever is later. Preventative maintenance or other corrective actions may be necessary (in addition to monitoring every 8,760 hours of operation) in order for owners or operators to ensure compliance at all times (consistent with the general duty clause 40 CFR 60.5470b(b)) with the required flow rate of 2 scfm or less).

Routing Emissions From the Rod Packing to a Process. Alternatively, an owner or operator may choose to comply with NSPS OOOOb by routing emissions from the rod packing to a process through a CVS. This option would achieve greater than or equal to the 2 scfm numerical limit as emissions would be routed to a process via a closed system which would limit emissions from the rod packing from being vented to the atmosphere. An owner or operator must ensure that the CVS is designed to capture and route all gases, vapors, and fumes to a process (40 CFR 60.5411b(a) and (c)). Additionally, an owner or operator would be required to design and operate the CVS with no detectable emissions and would be subject to bypass requirements (as applicable). Initial, monthly, and annual inspections (using OGI, EPA Method 21, or AVO (for monthly inspections only)) would be required to check for defects and detectable emissions.

Recordkeeping and Reporting Requirements. Owners or operators complying with the numerical emission limit must track and report in their annual report the cumulative number of hours of operation of each reciprocating compressor since startup, since the previous screening/volumetric flow rate emissions measurement, or since the previous reciprocating compressor repair/replacement of rod packing, as applicable. Their annual report must also include a description of the method used and the results of the volumetric flow rate measurement or emissions screening, as applicable. Lastly, owners or operators must maintain records and report each deviation from the emission limit standard that occurred during the reporting period, the date and time the deviation began, duration of the deviation and a description of the deviation.

For a reciprocating compressor affected facility complying with the routing emissions from the rod packing to a process through a CVS, an owner or operator would be required to maintain records and report each reciprocating compressor that was constructed, modified, or reconstructed during the reporting period that is complying by using this option. In instances where a deviation from the standard has occurred during the reporting period, an owner or operator would be required to provide information on the date and time the deviation began, the duration of the deviation, and a description of the deviation. Additionally, they would be required to report of the dates of each cover and CVS inspection, whether defects or leaks are identified, and the date of repair or the date of anticipated repair if repair is delayed would be included in the annual report. Where bypass requirements apply, the date and time of each bypass alarm or each instance the key is checked out would be included in the annual report.

2. EG OOOOc

Based on the analysis presented in section XII.E.2 of the November 2021 proposal preamble (86 FR 63214–63220; November 15, 2021), the proposed BSER for EG OOOOc for reducing methane emissions from existing reciprocating compressors was the replacement of the rod packing based on an annual monitoring threshold. Under the November 2021 proposal, the owner or operator of a reciprocating compressor designated facility would have been required to monitor the rod packing emissions annually by conducting flow rate measurements. When the measured flow rate exceeded 2 scfm (in pressurized mode), replacement of the rod packing would have been required. Alternatively, the November 2021 proposal would have also provided owners and operators the compliance alternative of routing rod packing emissions to a process via a CVS under negative pressure to comply with the rule.

a. Standard Proposed Changes

Based on the same public comment considerations and reasoning as explained above (see sections IV.I.1.b.i and ii of this preamble) for the proposed NSPS OOOOb reciprocating compressor rule changes, the EPA is proposing the same changes and requirements under EG OOOOc as presumptive standards for designated facilities.

b. Summary of Proposed Standards

Designated Facility. The EPA is proposing to define a reciprocating compressor designated facility as each reciprocating compressor, which is a single reciprocating compressor. A reciprocating compressor located at a well site is not a designated facility under this subpart. A reciprocating compressor located at a centralized production facility is a designated facility under this subpart.

Proposed Presumptive Standards. The proposed presumptive standards and BSER for existing reciprocating compressors are the same as those being proposed for new reciprocating compressors (see section IV.I.1.b.iii of this preamble). The requirements to monitor the volumetric flow rate from a reciprocating compressor based on hours of operation, and to repair or replace the rod packing and to conduct any necessary repair and maintenance in order to maintain a flow rate at or below 2 scfm, would not result in any additional capital expenditures or retrofit considerations that would warrant different requirements. Alternatively, as with new sources, owners or operators of existing reciprocating compressors would be allowed to comply by routing rod packing emissions to a process via a CVS.

J. Storage Vessels

1. NSPS OOOOb

a. November 2021 Proposal

Storage Vessel Affected Facility. In the November 2021 proposal, the EPA proposed to retain the current VOC standards for storage vessels (95 percent reduction) and proposed for the first-time standards for reducing methane emissions from storage vessels (95 reduction). In addition, for both VOC and methane standards, the EPA proposed to define a storage vessel affected facility as a tank battery or a single storage vessel that is not part of a tank battery, with the potential for VOC emissions of 6 tpy or greater.[230] The standards in NSPS OOOOa apply to single storage vessels with potential VOC emissions of 6 tpy or greater, although the EPA has long observed that these storage vessels are typically located as part of a tank battery. See 76 FR 52738, 52763 (August 23, 2011). Further, the 6 tpy applicability threshold was established by directly correlating the cost to control different levels of VOC emissions based on the use of a single vapor recovery or combustion control device, regardless of the number of storage vessels routing emissions to that control device, and control of 6 tpy VOC was cost effective using that single control device. *Id.* at 52763–64. Therefore, in the November 2021 proposal, the EPA proposed to define a tank battery as a group of storage vessels that are physically adjacent and that receive fluids from the same source (*e.g.,* well, process unit, compressor station, or set of wells, process units, or compressor stations) or which are manifolded together for liquid or vapor transfer. The EPA proposed that to determine whether a single storage vessel is an affected facility, the owner or operator would compare the 6 tpy VOC threshold to the potential emissions from that individual storage vessel; to determine whether a tank battery is an affected facility, the owner or operator would compare the 6 tpy VOC threshold to the aggregate potential emissions from the group of storage vessels in the tank battery. For new, modified, or reconstructed sources, the EPA proposed that if the potential VOC emissions from a storage vessel or tank battery exceeds the 6 tpy threshold, then it is a storage vessel affected facility and controls would be required. Additionally, the EPA proposed an emissions limit requiring 95 percent reduction as the BSER for reducing VOC and methane emissions from new, modified, or reconstructed storage vessel affected facilities. The EPA also requested comment on increasing combustion efficiency to 98 percent control and on requiring additional monitoring of the control device. See IV.G of this preamble for discussion related to combustion control devices.

Modification. In the November 2021 proposal, the EPA proposed specific provisions to specify what circumstances constitute a modification of an existing storage vessel or tank battery, and thus subject it to the proposed NSPS OOOOb. The EPA proposed that a single storage vessel or tank battery is modified when certain physical or operational changes are made (86 FR 63178; November 15, 2021) to the single storage vessel or tank battery which result in an increase in the potential methane or VOC emissions. The EPA proposed that the owner or operator would be required to recalculate the potential VOC emissions when any of these actions occurred on an existing tank battery, to determine if a modification occurred. The EPA proposed that an existing tank battery would become subject to the proposed NSPS OOOOb if it is modified pursuant to this definition of modification and its potential VOC emissions exceeded the proposed 6 tpy VOC emissions threshold.

Legally and Practicably Enforceable. The EPA proposed to clarify the term ''legally and practicably enforceable'' as it related to determining applicability of the storage vessel standards, The intent of this proposed definition (86 FR 63201; November 15, 2021) was to provide clarity to owners and operators claiming the storage vessel is not an affected facility in NSPS OOOOb, due to legally and practicably enforceable limits that limit their potential for VOC emissions below 6 tpy.

b. Changes From November 2021 Proposal

Storage Vessel Affected Facility. In this supplemental proposal, the EPA is proposing that a storage vessel affected facility is a tank battery which has the potential for VOC emissions equal to or greater than 6 tpy or the potential for methane emissions equal to or greater than 20 tpy. Specifically, the EPA is proposing to define a tank battery as a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel if there is only one storage vessel is present, or the individual storage vessels at the site are not manifolded for liquid transfer. Commenters generally supported basing the potential for emissions on a tank battery instead of an individual storage vessel. The EPA received several comments that suggested changes to the definition of tank battery relating to how the tanks were manifolded and the proximity of tanks within the tank battery. Specifically, these commenters recommended that the definition of tank battery not include the term ''adjacent'' and should be based on tanks that are manifolded by liquid line.[231] Commenters suggested these changes to avoid confusion around applicability and to align with existing state programs.[232] The EPA agrees that these changes reflect our intent that a group of storage vessels which are manifolded together by liquid line operate as a system and, as such, share the same control, the cost of which was the basis for defining the applicability threshold; the total throughput to the tank battery is the basis for determining the potential for VOC and methane emissions for the tank battery, based on the maximum average daily throughput to the tank battery. This rationale holds regardless of the physical proximity to each other and therefore the term ''adjacent'' does not add additional clarity. Also, because tank batteries with the potential for VOC and methane emissions (greater than or equal to the thresholds) are: (1) Storage vessel affected facilities which require control; and (2) those standards require that all vapors from the tank battery are routed through a CVS (*i.e.,* manifolded), it is not necessary to include the provision that vapor lines are manifolded in the definition of tank battery.

As stated above, the EPA is also proposing to include the 20 tpy

[230] For the reasons explained in the November 2021 proposal, the 6 tpy VOC applicability threshold would apply to both methane and VOC standards.

[231] See Document ID Nos. EPA–HQ–OAR–2021–0317–0810, EPA–HQ–OAR–2021–0317–0814 and EPA–HQ–OAR–2021–0317–0831.

[232] See Document ID Nos. EPA–HQ–OAR–2021–0317–0808 and EPA–HQ–OAR–2021–0317–0831.

potential for methane emission threshold for determining applicability to NSPS OOOOb. As discussed in the November 2021 proposal, the EPA determined that it is cost-effective to reduce methane emissions by 95 percent from existing tank batteries with potential methane emissions of 20 tpy. The EPA focused the November 2021 proposed NSPS OOOOb requirements on the 6 tpy VOC threshold because the EPA expects that most tank batteries will exceed the 6 tpy VOC threshold well before they exceed the 20 tpy methane threshold. However, based on our cost estimates, the EPA determined it is cost effective to control tank batteries if their methane emissions exceed 20 tpy, but the potential VOC emissions remain below 6 tpy. As such, in the unusual case that the methane threshold is triggered prior to the VOC threshold, the EPA determined it necessary to directly include the 20 tpy potential methane emissions threshold in the storage vessel affected facility definition.

The EPA also is proposing that a ''generally accepted model or calculation methodology'' used to determine VOC and methane emissions must account for flashing, working, and breathing losses. As discussed in the November 2021 proposal, both methane and VOC emissions from storage vessels are a result of working, breathing, and flashing losses. Flashing losses occur when a liquid with dissolved gases is transferred from a vessel with higher pressure (*e.g.,* separator) to a vessel with lower pressure (*e.g.,* storage vessel), thus allowing dissolved gases and a portion of the liquid to vaporize or flash. In the Crude Oil and Natural Gas source category, flashing losses occur when crude oils or condensates flow into a storage vessel from a separator operated at a higher pressure. Typically, the higher the operating pressure of the upstream separator, the greater the flash emissions from the storage vessel. See 86 FR 63198 (November 15, 2021). For tank batteries with flashing losses, those emissions can dwarf working and breathing losses from the same tank battery. There are many ''generally accepted'' models or calculation methodologies for estimating storage vessel emissions, but they do not all estimate flash emissions. Therefore, it is important to specify in the rule the EPA's requirement that emissions calculations account for such emissions when flash emissions occur.

Additionally, the EPA is including in this supplemental proposal regulatory text which instructs the owner or operator on how to determine the potential for VOC or methane emissions as the cumulative emissions from all storage vessels within the tank battery according to certain timelines; for each tank battery located at a well site or centralized production facility the determination must occur 30 days after startup of production, or within 30 days after a physical or operational action which may trigger a modification or reconstruction; or for each tank battery located at a compressor station or onshore natural gas processing plan, the determination must occur prior to startup of the compressor station or onshore natural gas processing plant (or within 30 days after an action which may trigger reconstruction or modification). These timelines are consistent with the timelines provided in NSPS OOOOa for determining the potential for VOC emissions after startup of production (for a well site) or startup of the compressor station or onshore natural gas processing plant but are being proposed to also include timelines for centralized production facilities as well as timelines for determining the potential for VOC and methane emissions following an action which may trigger reconstruction or modification. The EPA believes this proposed regulatory text will provide direction and clarity to owners and operators for when the potential for VOC and methane emissions determinations must be made based on potentially triggering events. See the following discussion regarding reconstruction and modification.

Reconstruction and Modification. The EPA is proposing the following changes from the November 2021 proposal related to definitions for reconstruction and modification for storage vessels. This proposal includes a definition of ''reconstruction'' as well as ''modification'' at 40 CFR 60.5365b(e)(3) for determining if an existing tank battery becomes a storage vessel affected facility subject to NSPS OOOOb. The proposed rule will apply to sources that are new, reconstructed, and modified sources after November 15, 2021. In the November 2021 proposal the EPA discussed our rationale for proposing specific actions which lead to an increase in VOC and methane emissions and therefore, constitute a modification of an existing tank battery. Generally, that rationale was to provide clarity on actions which are considered a modification of a tank battery. See 86 FR 63198 (November 15, 2021).

In this proposed rule, the EPA is proposing two actions which constitute reconstruction: (1) Over half of the storage vessels are replaced in an existing tank battery that consists of more than one storage vessel; or (2) the provisions of 40 CFR 60.15 are met for the existing tank battery that consists of a single storage vessel. Section 60.15 of the General Provisions to part 60 states that reconstruction occurs when the replacement of new components exceeds 50 percent of the capital cost that would be required to construct a comparable entirely new facility and it is technologically and economically feasible to meet the applicable standard under part 60. Reconstruction applies irrespective of any change in emissions rate. ''Fixed'' capital cost is further defined at 40 CFR 60.15(c) as the capital needed to provide all of the depreciable components and 40 CFR 60.15(g) allows for individual subparts to include specific provisions to refine or delimit the concept of reconstruction. Finally, 40 CFR 60.15(d) and (e) provide that the owner or operator must notify the Administrator prior to the proposed replacement with an estimate of the fixed capital cost of replacement (among other items, see 40 CFR 60.15(d)) and upon receipt, the Administrator will determine if the proposed replacement constitutes reconstruction.

Based on our experience from NSPS OOOO and NSPS OOOOa, the predominant type of storage vessel expected to be covered by the proposed NSPS are fixed roof storage vessels, and as part of the storage vessel affected facility, have limited depreciable components beyond the storage vessel itself (*e.g.,* thief hatches and pressure relief devices). Because the EPA expects that each affected facility will undertake similar fixed capital cost replacements at storage vessel affected facilities, namely replacing one or more storage vessels, replacing thief hatches, and replacing pressure relief devices, we believe that it will serve as a burden reduction to industry to establish uniform criteria which constitute reconstruction. For a tank battery which consists of a single storage vessel, it may be possible that the cost of replacing the thief hatch, pressure relief device or other depreciable components could exceed 50 percent of the cost of an entirely new storage vessel, therefore the EPA is proposing that the provisions of 40 CFR 60.15 would apply. The EPA requests comment on this assumption that the costs of replacement of all depreciable components on a single storage vessel could exceed 50 percent of the cost of an entirely new storage vessel. For a tank battery which consists of more than a single storage vessel, we believe that the cost of replacing storage vessel components such as thief hatches and pressure relief devices, in comparison to the cost of constructing an entirely new storage vessel affected facility, will not exceed 50 percent of the cost of constructing a comparable new storage vessel affected facility. Therefore, the EPA is proposing to simplify and streamline the reconstruction determination for tank batteries by defining reconstruction at a tank battery with more than a single storage vessel as replacement of 50 percent of the storage vessels in the tank battery. This defined reconstruction action will eliminate the need for the owner or operator to submit the notification in 40 CFR 60.15(d) and await the EPA's response under 40 CFR 60.15(e), before undertaking a replacement.

An important factor in determining whether over 50 percent of the storage vessels in an existing tank battery has been replaced is the time period for making such assessment. Consider the following scenario: an owner replaces one-third of the storage vessels in an existing tank battery and, shortly thereafter, replaces another third of the storage vessels in that tank battery. The owner has replaced 60 percent of the storage vessels in that tank battery in total; however, without specifying the time frame for assessing reconstruction, it is unclear whether the tank battery is ''reconstructed'' because over half of the storage vessels in the tank battery have been replaced, or the replacements are two separate programs and therefore should not be aggregated for purposes of determining reconstruction. For the reasons discussed in section IV.D and IV.E of this preamble, the EPA is proposing to interpret natural gas-drive pneumatic controller and pneumatic pump replacements to include all natural gas-driven pneumatic controllers and pneumatic pumps which commence replacement (but are not necessarily completed) within any 2-year period in determining whether the replacements constitute reconstruction. The EPA solicits comment on whether to similarly set a specific time period (or rolling time period) within which replaced storage vessels in an existing tank battery will be aggregated towards determining whether the 50 percent replacement threshold has been exceeded, and if so, whether a 2-year time frame or another time frame is appropriate for determining reconstruction to a tank battery with more than a single storage vessel.

Related to modifications, the EPA explained in the November 2021 proposal that actions occurring at a well site, such as refracturing a well or adding a new well that sends these liquids to the tank battery at the well site or centralized production facility, would result in an increase in VOC and methane emissions based on an increase in volumetric throughput to the tank battery. See 86 FR 63199 (November 15, 2021). However, this does not always hold true for tank batteries located at a compressor stations or onshore natural gas processing plants. In the September 15, 2020, rule (see 85 FR 57404), the EPA finalized a different framework for determining the potential for VOC emissions from storage vessels located at compressor stations and onshore natural gas processing plants, based on comments received on the September 15, 2020, rule that storage vessels located at these types of facilities are designed to receive liquids from multiple well sites that may startup production over a longer period of time.[233] To account for this future throughput to the storage vessels, compressor stations and natural gas processing plants use analysis based on the future maximum throughput capacity which is then used to obtain permits. Therefore, the EPA agrees that when a tank battery at a compressor station or onshore natural gas processing plant receives additional throughput which has already been accounted for in the design capacity of that tank battery and included as a legally and practically enforceable limit in a permit for the tank battery, that additional throughput does not result in an emission increase from the tank battery because those emissions have already been accounted for in the permit.

In summary, the EPA is proposing that a modification occurs to an existing tank battery located at a well site or centralized production facility when the tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput and the potential for VOC or methane emissions increases above the applicable thresholds. Separately, the EPA is proposing that a modification occurs to an existing tank battery located at a compressor station or onshore natural gas processing plant when the tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent determination for VOC or methane missions (*e.g.,* permit) based on the design capacity of such tank battery. In addition, as proposed in November 2021, modification is also triggered by the following two events: (1) A storage vessel is added to an existing tank battery; and/or (2) one or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases.

One commenter expressed concerns that the change to a tank battery (in NSPS OOOOb) versus a single tank (in NSPS OOOOa) will cause confusion with the requirements of NSPS OOOOa because it creates a disconnect with how the previous NSPS for this source category applies the affected facility status to storage tanks. The commenter states that creating separate ''classifications'' within the NSPS based on dates of construction or modification will create additional burden when reviewing authorizations within the specified legislatively mandated time frames.[234] The EPA discusses the interplay and effective dates between prior standards applicable to the Crude Oil and Natural Gas source category in sections III.B, III.C and III.D of this preamble. However, to address specific questions regarding applicability to storage vessels which may be subject to NSPS OOOO, NSPS OOOOa, or EG OOOOc, the EPA is providing a discussion of applicability for several anticipated scenarios which may be triggered by a potential modification action described above. For purposes of the scenarios below, the EPA is using the proposed definition of a tank battery, which includes a single storage vessel if only one storage vessel is present.

Scenario One—An existing tank battery has the potential for methane emissions greater than or equal to 20 tpy methane, therefore it is a designated facility for purposes of EG OOOOc. Subsequently, one of the proposed physical or operational changes in NSPS OOOOb at 40 CFR 60.5365b(e)(3)(ii) (*i.e.,* adds a storage vessel to an existing tank battery; adds capacity to an existing tank battery; or receives additional fluids) occurs. In order to determine if modification has occurred to the existing tank battery, the owner or operator would calculate the potential for VOC and methane emissions in accordance with the proposed 40 CFR 60.5365b(e)(2). If the potential for either VOC or methane is above the proposed threshold, the tank battery is a modified storage vessel affected facility subject to NSPS OOOOb. If the potential for both VOC and methane is not above the threshold, the tank battery is not a modified (or reconstructed) storage vessel affected facility for purposes of NSPS OOOOb and remains a designated facility for purposes of EG OOOOc.

[233] See Document ID No. EPA–HQ–OAR–2017–0473–1261.

[234] See Document ID No. EPA–HQ–OAR–2021–0317–0763.

Scenario Two—An existing tank battery is not a designated facility under EG OOOOc (*i.e.,* the potential for methane emissions is less than 20 tpy). Like scenario 1, subsequently, one of the proposed physical or operational changes in NSPS OOOOb occurs and the owner or operator calculates the potential for VOC and methane emissions. If the potential for either VOC or methane emissions is above the proposed threshold, the tank battery is a modified storage vessel affected facility subject to NSPS OOOOb. If the potential for both VOC and methane is not above the proposed threshold, the tank battery is not a modified storage vessel affected facility for the purposes of NSPS OOOOb and is also not a designated facility under EG OOOOc.

Scenario Three—An existing storage vessel is a single storage vessel subject to either NSPS OOOO or NSPS OOOOa and is part of a tank battery. One of the proposed physical or operational changes in NSPS OOOOb occurs and the owner or operator calculates the potential for VOC and methane emissions from the entire tank battery. If the potential for either VOC or methane is above the threshold, the tank battery is a modified storage vessel affected facility subject to NSPS OOOOb, and the single storage vessel would continue to be subject to the applicable NSPS OOOO or NSPS OOOOa. However, where a facility is subject to multiple standards, the general practice is to streamline compliance by complying with the more stringent standard, which would in effect meet the less stringent standards. If the potential for both VOC and methane is not above the proposed threshold, the single storage vessel is not modified for the purposes of NSPS OOOOb and remains subject to NSPS OOOO or NSPS OOOOa.

Scenario Four—An existing storage vessel is a single storage vessel and is subject to either NSPS OOOO or NSPS OOOOa. The single storage vessel is not a designated facility under EG OOOOc because the potential for methane emissions is less than 20 tpy. One of the proposed physical or operational changes in NSPS OOOOb occurs and the owner or operator calculates the potential for VOC and methane emissions from the single storage vessel. If the potential for either VOC or methane is above the proposed threshold, the single tank is a tank battery which is a modified storage vessel affected facility subject to NSPS OOOOb, as well as NSPS OOOO or NSPS OOOOa. Where a facility is subject to multiple standards, the general practice is to streamline compliance by complying with the more stringent standard, which would in effect meet the less stringent standards; however, streamlining may not be necessary here if the EPA finalized the proposed 95 percent reduction, which is the storage vessel standard in NSPS OOOO and NSPS OOOOa. If the potential for both VOC and methane is not above the threshold, the single tank is not modified for the purposes of NSPS OOOOb and remains subject to NSPS OOOO or NSPS OOOOa.

Removed From Service. Finally, in NSPS OOOO and NSPS OOOOa, the EPA includes provisions to address the status of storage vessel affected facilities which are physically isolated and disconnected from the process for purposes other than maintenance, which is referred to as ''removed from service''.[235] Those regulations also include a framework for determining the affected facility status of such storage vessels when they are ''returned to service'', either by: (1) Being reconnected to the original source of liquids, (2) used to replace any storage vessel affected facility, or (3) installed in any location covered by the subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water. The EPA is including these same provisions in the proposed NSPS OOOOb for situations where there is more than one storage vessel in a tank battery and the entire tank battery is removed from or returned to service. Additionally, the EPA is proposing language to address situations when only a portion of the tank battery is removed from, or returned to, service. Specifically, the EPA is proposing to require complete emptying and degassing of the entire tank battery, or the portion of the tank battery that is being removed, for it to be considered ''removed from service''. Submission of a notification that these emptying and degassing requirements are met would also be required. Further, when a portion of a storage vessel affected facility is removed from service, in addition to the requirements above, the portion of the tank battery must be disconnected from the tank battery such that the portion is no longer manifolded to the tank battery by liquid or vapor transfer. When a tank battery is returned to service, it would retain the same applicability status that applied prior to removal from service. For tank batteries where only a portion of the tank battery is returned to service and it is reconnected to the original source of liquids, it remains a storage vessel affected facility subject to the same requirements that applied before being removed from service. If a storage vessel is used to replace a storage vessel affected facility, or portion of a storage vessel affected facility, or used to expand a storage vessel affected facility, it assumes the affected facility status of the storage vessel affected facility being replaced or expanded.

Request for Additional Comment. In addition to the proposed changes or clarifications described above, the EPA is soliciting comment on including a requirement to equip thief hatches with alarms, automated systems to monitor for pressure changes, or use of automatically closing thief hatches. Commenters noted that open thief hatches and deteriorated seals around tank openings are significant emissions sources at tank batteries. The EPA is aware that some owners and operators utilize automated systems to alert when pressure changes occur that could signal an open thief hatch. Additionally, where automated systems are not available, there are alarms that could be utilized to alert (via audible alarm or remote notification to the nearest field office) that an unseated thief hatch is present.[236] The EPA is soliciting information on the costs, operation, and feasibility of installing these automated systems, alarms, or the use of automatically closing thief hatches.

c. Summary of Proposed Requirements

In this proposed rule, owners and operators of storage vessel affected facilities must reduce methane and VOC emissions by 95 percent. Consistent with provisions of NSPS OOOO and NSPS OOOOa, the proposed rule also includes the option where if the owner or operator maintains the uncontrolled actual VOC emissions at less than 4 tpy and the actual methane emissions at less than 14 tpy as determined monthly for 12 consecutive months, controls are no longer required. Storage vessel affected facilities which use a control device to reduce emissions must equip each storage vessel in the tank battery with a cover and manifold all storage vessels in the tank battery such that all vapors are shared among the headspaces of the storage vessel affected facility. The tank battery must be equipped with a CVS which routes all emissions to a control device. The proposed rule would require that when using a flare, the flare must meet the requirements in 40 CFR 60.18, which the EPA is proposing to strengthen by including additional

[235] See 78 FR 58435 (September 23, 2013), 79 FR 79022 (December 31, 2014), 80 FR 48262 (August 12, 2015), and 81 FR 35824 (June 3, 2016).

[236] See Document ID No. EPA–HQ–OAR–2021–0317–0814.

requirements (as discussed in section IV.H of this preamble), and that monitoring, recordkeeping, and reporting be conducted to ensure that the flare is constantly achieving the required 95 percent reduction. More information on the control device monitoring and compliance provisions is provided in section IV.G of this preamble; additionally, notifications made through the super-emitter response program could help identify potential violations as provided in section IV.C of this preamble. If the storage vessel affected facility does not have flashing emissions and is not located at a well site or centralized production site, the owner or operator may use an internal or external floating roof to reduce emissions.

In each annual report, owners and operators would be required to identify each storage vessel affected facility that was constructed, modified, or reconstructed during the reporting period and must document the emission rates of both VOC and methane individually. The annual report must include deviations that occurred during the reporting period and information for control devices tested by the manufacturer or the date and results of the control device performance test for control devices not tested by the manufacturer. The report also must include the results of inspections of covers and CVS and the identification of storage vessel affected facilities (or portion of storage vessel affected facility) removed from service or returned to service. For storage vessel affected facilities which comply with the uncontrolled 4 tpy VOC limit or 14 tpy methane limit, the report must include changes which resulted in the source no longer complying with those limits and the dates that the source began to comply with the 95 percent reduction standard.

Required records include documentation of the methane and VOC emissions determination and methodology, records of deviations and duration, records for the number of consecutive days a skid-mounted or permanently mobile-mounted storage vessel is on the site, the latitude and longitude coordinates of each storage vessel affected facility, and records associated with a manufacturer tested control device. Required records also include records demonstrating continuous compliance including inlet gas flow rate, presence of pilot flame, operation with no visible emissions, maintenance and repair logs, manufacturer's operating instructions, and dates that each storage vessel affected facility (or portion of storage vessel affected facility) is removed from service or returned to service. For storage vessel affected facilities which comply with the uncontrolled 4 tpy VOC or 14 tpy methane limit, records of changes which resulted in the source no longer complying with those limits and the dates that the source began to comply with the 95 percent reduction standard, including records of the methane and VOC determination and methodology. All associated records that demonstrate proper design and operation of the CVS, cover and control device also must be maintained (see section IV.G and IV.J. of this preamble).

2. EG OOOOc

The EPA is also proposing presumptive standards to reduce methane for existing storage vessel affected facilities in this action that remain unchanged from the November 2021 proposal and are similar to those proposed for NSPS OOOOb. Because the BSER for reducing VOC and methane emissions are the same, the proposed presumptive standard is to reduce methane emissions by 95 percent. Some commenters expressed that creating separate classifications (*e.g.,* tank batteries vs single tanks) within the NSPS based on dates of construction or modification will create additional burden when reviewing authorizations within the specified legislatively mandated time frames. Another commenter requested that EPA clarify whether other individual storage vessels in an existing tank battery remain affected facilities under NSPS OOOO or NSPS OOOOa, as applicable, or become part of the modified tank battery under NSPS OOOOb.[237] The EPA discusses the interplay and effective dates between prior standards applicable to the Crude Oil and Natural Gas source category in sections III.B, III.C and III.D of this preamble and provides example scenarios, which the EPA believes will provide guidance to regulators and the regulated community.

K. Covers and Closed Vent Systems

1. NSPS OOOOb

a. November 2021 Proposal

In the November 2021 proposal, the EPA proposed CVS requirements for certain affected facilities to ensure that emissions are captured and routed to a process or control device, dependent on the standard for the affected/designated facility. The affected/designated facilities for which the EPA proposed the use of a CVS were wells (oil wells when routing associated gas to a control device), storage vessels, centrifugal compressors (wet seal), reciprocating compressors, pneumatic pumps, and process unit equipment affected/designated facilities. Additionally, for storage vessels using a control device to reduce emissions and centrifugal compressors with wet seals using a degassing system, the EPA proposed the use of covers to form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or the centrifugal compressor wet seal fluid degassing system. The cover requirements ensure that all emissions are captured from those emissions sources and routed through a CVS to a control device, or in the case of centrifugal compressors, to a control device or to a process. This section discusses the cover and CVS requirements for those affected/designated facilities that are located at well sites, centralized production facilities, and compressor stations. See the discussion on CVS in section IV.L of this preamble for covers and CVS located at natural gas processing plants.

In the November 2021 proposal, the EPA proposed that covers and CVS must be designed and operated with no detectable emissions (NDE). Further, the EPA proposed that where a CVS is used to route emissions from an affected facility, the owner or operator would demonstrate there are no detectable emissions from the covers and CVS through OGI or EPA Method 21 monitoring conducted during the fugitive emissions survey. Where emissions are detected, the emissions would be considered a violation of the NDE standard and thus a deviation,[238] and corrective actions to complete all necessary repairs as soon as practicable would be required. The EPA also solicited comment on whether to include the option to continue utilizing monthly AVO surveys as demonstrations of NDE from a CVS associated with a pneumatic pump but did not propose that option specifically. We stated that because we anticipated that CVS associated with pneumatic pumps would be located at well sites subject to fugitive emissions monitoring, the monthly AVO option was not necessary. However, we solicited comment on whether there are circumstances where a CVS associated with a pneumatic pump is located at a well site not otherwise subject to

[237] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

[238] A deviation includes any instance in which an affected source fails to meet any emission limit, operating limit, or work practice standard; a deviation suggests potential violation with the applicable performance standard.

fugitive emissions monitoring and where OGI (or EPA Method 21) would be an additional burden.

b. Changes From November 2021 Proposal

In this supplemental proposal, the EPA is proposing specific revisions to the requirements for CVS associated with the affected/designated facilities located at well sites, centralized production facilities, and compressor stations in the proposed NSPS OOOOb and EG OOOOc. First, the EPA is proposing the same design and operational requirements for all CVS when routing emissions to a control device or when routing emissions to a process, regardless of which affected/designated facility is using the CVS. These proposed standards would apply to wells (oil wells when routing associated gas to a control device), centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, and process unit equipment affected/designated facilities. See section IV.L of this preamble for additional discussion related to process unit equipment affected/designated facilities at onshore natural gas processing plants.

For these affected/designated facilities, the EPA is proposing the capture and routing of emissions through a CVS to a control device or process as part of the BSER, or an alternative to the BSER for specific situations such as technical infeasibility to apply BSER. The EPA finds that the demonstration of continuous compliance for these CVS should include the same robust standards to ensure the CVS are designed and operated to capture and route all emissions to the control device regardless of which affected/designated facility is using the CVS. The proposed standards for CVS include upfront engineering (Professional Engineer or in-house engineer) design analysis and certifications, an emissions limit that requires design and operation with no identifiable emissions, initial and periodic inspections of the CVS, and continuous monitoring of CVS bypass systems (unless equipped with a seal or closure mechanism). Therefore, in this proposal, the EPA is standardizing the design and operational requirements for CVS, regardless of their location or use (route to a control device or route to a process).

The EPA is proposing to change the design and operational requirements for CVS (except for those associated with self-contained pneumatic controllers) from operation with NDE to operation with no identifiable emissions. The proposed change of terminology is not intended to change the stringency of the CVS requirements, which require that each CVS capture and route all gases, vapors, and fumes to a control device or a process, but it will clarify the design and operational standards, and the obligations on the part of the owner or operator if a leak is detected from the CVS during the inspections to ensure compliance with the no identifiable emissions standard.

Based on comments received on the November 2021 proposal, there appears to be confusion whether the proposed NDE standard would be an emissions limit or a work practice standard. For example, one commenter [239] stated that as written, the NDE standard would be a work practice standard because ''[a]s with all other fugitive emissions components, detection of a leak (in this case, defined as detectable emissions) through routine LDAR monitoring triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented.'' This interpretation of the standard is not correct. In fact, CVS must be designed and operated to route all gases, vapors, and fumes to a control device or to a process, which is defined as an emission limit of NDE. The corrective actions (in the form of the repair provisions) are provided to ensure that owners and operators bring the CVS back into compliance with the NDE emission limit as quickly as possible.

Past efforts in NSPS OOOO and NSPS OOOOa to apply an NDE standard as an emission limitation, while still allowing repair, delay of repair or exceptions for unsafe and difficult to inspect equipment, may appear to condone a ''grace period'' during which compliance with an emissions limit is not required. Because the NDE standard in NSPS OOOO and NSPS OOOOa was established as an emissions limit, operation in exceedance of that limit is a deviation,[240] even if the repair provisions are followed.

Similarly, the EPA is proposing an emissions limit for covers and CVS in this supplemental proposal for NSPS OOOOb and EG OOOOc. However, NDE is a term closely linked with EPA Method 21, and is defined based on an instrument reading in units of ppmv. Because the EPA is proposing compliance inspections for covers and CVS using optical gas imaging and AVO, no instrument reading in ppmv is available. Therefore, the EPA is proposing the design and operational standard as an emissions limit of no identifiable emissions, which is more appropriate for the methods of detection required.

To ensure compliance with the no identifiable emissions design and operational standard for covers and CVS located at well sites, centralized production facilities, and compressor stations, the EPA is proposing that owners or operators would conduct initial and quarterly OGI inspections (except for the Alaska North Slope which is annually). Any identified emissions would be a violation of this emissions limit and would be subject to repair with a first attempt completed within 5 days and final repair within 30 days of identification. If the owner or operator is using the EPA Method 21 alternative for their fugitive emissions components, then any instrument reading greater than 500 ppmv above background is considered identified emissions, would be a potential violation of the no identifiable emissions standard, and would require repair within the same 5- and 30-day timeframe to bring the CVS back into compliance.

The EPA is also proposing to require AVO inspections for CVS and covers located at well sites, centralized production facilities and compressor stations. The EPA is proposing that AVO inspections of CVS and covers must occur at the same frequency specified for fugitive emissions components affected facilities located at the same type of site. As discussed in section IV.A.1.a.ii of this preamble, the EPA is proposing that CVS and covers located at a well site, centralized production facility, or compressor station site, which are not associated with a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, or storage vessel affected facility, are fugitive emissions components and subject to those standards, which include periodic OGI (or EPA Method 21 as an alternative) and monthly or bimonthly AVO inspections. Because we are aligning the CVS associated with well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, or storage vessel affected facilities inspections with the frequency of inspections under the fugitives program, there should be no additional cost associated with conducting these AVO inspections of CVS that are not fugitive emissions

[239] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

[240] A deviation signals possible violation with the performance standard for an affected facility because compliance is no longer demonstrated due to such exceedance.

components at the same time and at the same place, and we believe that identifying and repairing such leaks is consistent with the proposed requirement at 40 CFR 60.5370b(b) in a manner consistent with good air pollution control practice for minimizing emissions. See section IV.A of this preamble for a full discussion of the fugitive emissions requirements.

The EPA did not receive comment in response to our request regarding the burden of OGI (or EPA Method 21) monitoring for CVS associated with pneumatic pumps at well sites. Therefore, the EPA is not proposing separate standards for those CVS associated with pneumatic pumps and is proposing consistent standards for all CVS associated with affected/designated facilities under NSPS OOOOb or EG OOOOc.

As discussed in section IV.D of this preamble, the EPA is proposing that pneumatic controllers may comply with the zero-emission methane and VOC standard for pneumatic controllers by installing a self-contained pneumatic controller, which is a natural gas-driven controller designed so that there are no emissions to the atmosphere. These controllers are designated as ''no identifiable emissions'' in the proposed rule. Because these are designed to contain all gases, vapors, or fumes from the controller, the EPA finds it appropriate to apply the same continuous compliance requirements to self-contained controllers as those for covers and CVS described in this section. That is, the EPA is proposing to require the operation of self-contained pneumatic controllers with no identifiable emissions, as demonstrated through quarterly OGI monitoring. Any emissions identified would be a violation of the zero emissions standard. The repair requirements described for CVS would also apply to bring the self-contained pneumatic controller back into compliance with the zero emissions standard.

As discussed in section IV.B of this preamble, the EPA also is proposing provisions for the use of alternative test methods that employ alternative periodic screening technologies or continuous monitoring systems. The EPA is proposing to allow use of alternative test methods to replace the use of OGI for demonstrating continuous compliance of the no identifiable emissions standard for covers and CVS. The EPA recognizes that the allowable minimum detection thresholds of the screening technologies used in the alternative periodic screening approach may not be capable of identifying all of the potential emissions from these sources; however we find that well designed, maintained, and certified covers and CVS systems are not prone to leaks, and the majority of emission events from these systems can be attributed to short-term operational events or malfunctions that would be at a level easily identified by screening technology meeting the allowable minimum detection thresholds. The EPA considers the use of more frequent surveys (monthly to quarterly) using approved screening technologies and either annual (if required based on minimum detection threshold and frequency) or OGI surveys resulting from emissions detected during screening would ensure equivalent compliance assurance of the no identifiable emissions standard as the quarterly OGI surveys paired with monthly or bimonthly AVO inspections. The EPA solicits comments on the use of the alternative periodic screening approach as an alternative compliance assurance for covers and CVS associated with affected/designated facilities, and we solicit comments that the minimum detection thresholds summarized in Tables 20 and 21 (section IV.B of this preamble) are suitable for this purpose.

c. Summary of Proposed Requirements

The EPA is proposing standards which apply to CVS at a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, or process unit equipment affected/designated facility. The EPA also is proposing standards for covers at a centrifugal compressor and storage vessel affected/designated facility. This summary is limited to covers and CVS located at well sites, centralized production facilities, and compressor stations. Covers and CVS located at natural gas processing plants (process unit equipment affected/designated facilities) are discussed in section IV.L of this preamble.

Each CVS must be designed and operated to capture and route all gases, vapors, and fumes to a process or to a control device and comply with an emissions limit of no identifiable emissions. Initial and continuous compliance of the no identifiable emissions standard would be demonstrated through OGI monitoring and AVO inspections conducted at the same frequency as the fugitive emissions monitoring for the type of site. Specifically, for the well sites and centralized production facilities where a CVS is present, quarterly OGI and bimonthly AVO would be required; for compressor stations, quarterly OGI and monthly AVO would be required. If the CVS is equipped with a bypass, the bypass must include a flow monitor and sound an alarm to alert personnel that a bypass is being diverted to the atmosphere, or it must be equipped with a car-seal or lock-and-key configuration to ensure the valve remains in a non-diverting position. To ensure proper design, an assessment must be conducted and certified by a qualified professional engineer or in-house engineer. Covers must form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or over the centrifugal compressor wet seal fluid degassing system and each cover opening shall be secured in a closed, sealed position (*e.g.,* covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening.

Each CVS must be inspected using OGI or EPA Method 21 to ensure that the CVS operates with no identifiable emissions. Annual visual inspections to check for defects, such as cracks, holes, or gaps) must be conducted and monthly (compressor stations) or bimonthly (well sites and centralized production facilities) AVO inspections for leaks must be conducted would be a potential violation of the no identifiable emissions standard. Further, any leak detected would be subject to repair, with a first attempt at repair at five days and final repair within 30 days. While awaiting final repair, covers must have a gasket-compatible grease applied to improve the seal. Delay of repair is allowed where the repair is infeasible without a shutdown, or it is determined that immediate repair would result in emissions greater than delaying repair. In all instances, repairs must be completed by the end of the next shutdown. Unsafe to inspect and difficult to inspect parts of the closed vent system may be designated as such but must be inspected according to a plan as frequently as possible, or every five years, respectively.

Records of CVS and cover inspections, CVS bypass monitoring, and CVS design and certifications must be maintained. The CVS certification must be submitted in the initial annual report. Because the requirements for CVS and covers have been aligned for all affected facilities which use a CVS or cover, a new reporting section has been created to contain the similar requirements. Recordkeeping sections for CVS inspections, covers, bypass monitoring and CVS design assessment also have been created which are applicable to all sources which use CVS and covers. This will streamline compliance as all affected facilities using the CVS and cover requirements of the rule will be subject to the same reporting and recordkeeping requirements.

L. Equipment Leaks at Natural Gas Processing Plants

1. NSPS OOOOb

a. November 2021 Proposal

In the November 2021 proposal, the EPA proposed new standards of performance for equipment leaks at natural gas processing plants by revising the equipment leak standards for onshore natural gas plants to apply more readily to process unit equipment that has the potential to emit methane even though not ''in VOC service.'' The EPA also proposed appendix K to provide a standard method for OGI monitoring, which allowed the EPA to consider a wider range of LDAR programs when evaluating BSER for equipment leaks at onshore natural gas processing plants. Specifically, the EPA proposed to require bimonthly OGI monitoring of valves, pumps, and connectors that have the potential to emit methane and VOC following the protocol specified in the proposed appendix K. As an alternative, the EPA proposed to allow for monthly monitoring of pumps, quarterly monitoring of valves, and annual monitoring of connectors that have the potential to emit methane and VOC following EPA Method 21, with a leak defined as any instrument reading above 2,000 ppm for pumps or 500 ppm for valves and connectors. The EPA utilized a Monte Carlo analysis to compare these programs and determined that they achieved equivalent emissions reductions. See 86 FR 63232 (November 15, 2021) for additional information. The November 2021 proposal also included requirements for a ''first attempt at repair'' for all identified leaks within five days of detection, as well as final repair completed within 15 days of detection (except when delay would be allowed).

Finally, in the November 2021 proposal, the EPA requested comments on certain topics. First, we requested comment on ways to streamline approval of alternative LDAR programs using remote sensing techniques, sensor networks, or other alternatives for equipment leaks at onshore natural gas processing plants, including whether providing an emission reduction target and equipment leak modeling tool to simulate LDAR under similar ''ideal'' program implementation conditions might facilitate future equivalency determinations. Second, we requested comment on: (1) Adding a requirement of OGI monitoring (or EPA Method 21 monitoring for sources opting for the alternative) on open-ended valves or lines equipped with closure devices to ensure no emissions are going to the atmosphere (*e.g.,* to ensure the cap seals the open end); and (2) allowing the use of OGI monitoring according to the proposed appendix K, to demonstrate compliance with the no detectable emissions requirements (in lieu of EPA Method 21) such as those for CVS at onshore natural gas processing plants.

b. Changes From November 2021 Proposal

In this supplemental proposal, the EPA is proposing specific requirements for the individual process unit equipment type included in the LDAR program at onshore natural gas processing plants. This section describes those specific requirements for pressure relief devices, open-ended valves or lines, and CVS.

Pressure Relief Devices. Consistent with the November 2021 proposal, the EPA is proposing to require bimonthly OGI monitoring (or quarterly EPA Method 21 monitoring, if the alternative is used) as well as monitoring of each pressure relief device within 5 calendar days after each pressure release to detect leaks using either OGI or EPA Method 21. A leak is detected if any emissions are observed using OGI, or if an instrument reading of 500 ppm or greater is provided using EPA Method 21. The EPA is proposing this requirement instead of requiring a NDE demonstration (which is also required in NSPS OOOOa) because after reviewing the record to NSPS KKK (the original LDAR requirements for onshore natural gas processing plants), it was clear that the basis for the standards for pressure relief devices was a routine LDAR program.[241] Because we have determined that OGI is BSER for equipment leaks at onshore natural gas processing plants, it is appropriate to require bimonthly OGI monitoring for this process unit equipment. In addition to this bimonthly OGI monitoring requirement, the EPA is also proposing to require OGI monitoring of each pressure relief device after each pressure release, as it is important to ensure the pressure relief device has reseated and is not allowing emissions to vent to the atmosphere. The EPA is soliciting comment on this change from a no detectable emissions standard to a bimonthly monitoring requirement. Where the EPA Method 21 option is used, we are proposing quarterly monitoring of the pressure relief device in addition of monitoring after each pressure relief. A leak is defined as an instrument reading of 500 ppm or greater when using EPA Method 21.

Open-Ended Valves or Lines. For open-ended valves or lines, the EPA is proposing to require closure devices to seal the open end, consistent with the requirements in NSPS OOOOa. Consistent with the November 2021 proposal, the proposed regulatory text would require this equipment standard (*i.e.,* cap, blind flange, plug, or a second valve) for open-ended valves and lines. The EPA solicited comment on whether to require bimonthly OGI monitoring for open-ended valves and lines in the November 2021 proposal. We are not proposing to require routine periodic monitoring for open-ended valves or lines. The primary control requirement for open-ended valves or lines is a closure device (*i.e.,* caps, blind flanges, plugs, or a second valve) and this standard is designed to achieve nearly 100 percent emission reductions. While it is possible that leaks past the closure device could occur, the EPA does not believe it would be cost-effective to require a full LDAR program for each open-ended valve or line, and has previously found this type of requirement not cost-effective for this type of facility.[242] However, the EPA recognizes that there are opportunities to identify when there is a leak past the closure device as part of daily operating duties or required OGI surveys for other process unit equipment. Therefore, the EPA is proposing a requirement to complete repairs on an open-ended valve or line so that the closure device seals the open end of the valve or line when emissions are identified through any means. The EPA notes that repairs for this type of leak are generally straightforward (*e.g.,* install new plug or cap) and cost-effective to complete. Further, the repair is necessary to comply with the general duty provisions of 40 CFR 60.5370b(b).

Closed Vent Systems. In NSPS OOOO and NSPS OOOOa, the EPA relied on separate CVS requirements for ones located at an onshore natural gas processing facility than those requirements for CVS used for other purposes in NSPS OOOO and NSPS OOOOa. In this proposal, the EPA is standardizing the requirements for CVS, as described in section IV.K of this preamble, with one difference.

For CVS associated with process unit equipment affected facilities that are

[241] See 49 FR 2645 (January 24, 1984) and EPA–450/3–82–024b.

[242] See Document ID Nos. EPA–HQ–OAR–2010–0505–0045 and EPA–HQ–OAR–2010–0505–7631.

used to route emissions from leaking equipment to a control device, the EPA is proposing a requirement to monitor the CVS at the same frequency (*i.e.,* bimonthly OGI in accordance with appendix K or quarterly EPA Method 21) as other equipment in the process unit and to repair any leaks identified during the routine monitoring. Additionally, when leaks are identified as part of daily operating duties by any means of detection, we are proposing to require repairs in order to be consistent with the good air pollution control practices for minimizing emissions specified in 40 CFR 60.5370b(b). We believe it is most efficient and cost effective to monitor the CVS at the same frequency and according to the same methodology as other equipment in the process unit equipment affected facility (*i.e.,* bimonthly OGI in accordance with appendix K or quarterly with EPA Method 21) and it is reasonable and prudent to require any leaks identified to be repaired.

These proposed standards differ from our November 2021 proposal, which maintained EPA Method 21 inspections for CVS associated with process unit equipment, consistent with what is required in NSPS OOOO and NSPS OOOOa. Both NSPS OOOO and NSPS OOOOa require initial monitoring of a CVS used to comply with the equipment leak standards using EPA Method 21 followed by annual monitoring using visual inspections for defects (if constructed of hard piping) or annually using EPA visual inspections for defects and EPA Method 21 inspections (if constructed of ductwork). In this supplemental proposal, the EPA is proposing to allow initial monitoring using OGI in accordance with appendix K (or EPA Method 21 as an alternative) and annual visual methods for CVS where each joint, seam, or other connection is permanently or semi-permanently sealed (hard piping). This approach for initial instrument monitoring and annual visual monitoring for defects is consistent with the hard-piping requirements in NSPS OOOO and NSPS OOOOa and is also consistent with the requirements for other affected facilities which use a hard-piped CVS to route to a control device.

Potential To Emit Methane or VOC. Consistent with the November 2021 proposal, the EPA is proposing to apply the LDAR standards to process unit equipment that has the potential to emit methane or VOC.[243] Further, the EPA is proposing that each piece of equipment is presumed to have the potential to emit methane or VOC unless an owner or operator demonstrates that the piece of equipment does not have the potential to emit methane or VOC. For a piece of equipment to be considered not to have the potential to emit methane or VOC, the owner or operator would need to demonstrate that the process fluids in contact with the process unit equipment do not contain either methane or VOC. Commenters[244] suggested that the EPA maintain the 10 percent by weight VOC concentration threshold and add a one percent by weight methane concentration threshold so as to exclude ethane product streams, produced water streams, and wastewater streams. However, no additional data or analyses were provided to demonstrate that a threshold of one percent by weight methane would be appropriate. Further, recent studies indicate that produced water and wastewater streams can be significant sources of VOC and/or methane emissions.[245] Therefore, the EPA maintains that a definition based on the potential to emit VOC or methane is appropriate to determine which process unit equipment must be monitored and repaired.

Repair Requirements. In this supplemental proposal, the EPA is proposing a definition of ''first attempt at repair'' consistent with the November 2021 proposal, which means an action taken for the purpose of stopping or reducing fugitive emissions to the atmosphere. First attempts at repair include, but are not limited to, the following practices where practicable and appropriate: tightening bonnet bolts; replacing bonnet bolts; tightening packing gland nuts; or injecting lubricant into lubricated packing. Further, we are proposing a definition of ''repaired,'' specific to process unit equipment affected facilities, meaning that equipment is adjusted, or otherwise altered, in order to eliminate a leak, and is re-monitored to verify that emissions from the equipment are below the applicable leak definition. Pumps subject to weekly visual inspections which are designated as leaking and repaired are not subject to remonitoring. We are adding these definitions to clarify the requirements for leak repair associated with process unit equipment. The EPA is not proposing to require replacement of leaking equipment with low-emissions (''low-e'') valves or valve packing or require drill-and-tap with a low-e injectable because it is not appropriate for all valve repairs. However, because this low-e equipment, which meets the specifications of API 622 or 624, generally will include a manufacturer written warranty that it will not emit fugitive emissions at a concentration greater than 100 ppm within the first 5 years, we believe that they can be a viable option for repair in some instances, as demonstrated by the remonitoring requirements in the rule.

As described in the November 2021 proposal, the EPA is proposing to allow for delay of repair for leaks identified with OGI (or EPA Method 21), where it is technically infeasible to complete repairs within 15 days without a process unit shutdown. Generally, a process unit shutdown will generate more emissions than allowing the leak to continue; therefore, we are proposing to retain this delay of repair provision.

Alternative Use of EPA Method 21. As discussed in the November 2021 proposal, the EPA is proposing to allow the use of EPA Method 21 as an alternative to the required OGI monitoring. However, unlike NSPS OOOO and NSPS OOOOa, the EPA is not cross-referencing the requirements in NSPS VVa and is instead proposing regulatory text which incorporates the requirements directly into 40 CFR 60.5401b, with conforming changes consistent with the OGI standards, as described above for pressure relief devices, CVS, and repairs.

c. Summary of Proposed Requirements.

The proposed standards will apply to the ''process unit equipment'' affected facility and will require that each piece of equipment that has the potential to emit methane or VOC conduct bimonthly (*i.e.,* once every other month) OGI monitoring in accordance with appendix K to detect equipment leaks from pumps, valves, connectors, pressure relief devices, and CVS. As an alternative to the bimonthly OGI monitoring, EPA Method 21 may be used to detect leaks from the same equipment as frequencies specific to the process unit equipment type (*e.g.,* monthly for pumps, quarterly for valves).

Furthermore, this proposed rule requires that any leaks identified by AVO, or other detection methods from any equipment in any service, including open-ended valves or lines, must be repaired. The proposed rule includes

[243] See 86 FR 63182 (November 15, 2021).

[244] See Document ID No. EPA–HQ–OAR–2021–0317–0808.

[245] ''Measurement of Produced Water Air Emissions from Crude Oil and Natural Gas Operations.'' Final Report. California Air Resources Board. May 2020. Available at: Measurement of Produced Water Air Emissions from Crude Oil and Natural Gas Operations (*ca.gov*).

And ''Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2019: Updates for Produced Water Emissions.'' April 2021. Available at: *https://www.epa.gov/sites/default/files/2021-04/documents/2021_ghgi_update_-_water.pdf.*

requirements for a first attempt at repair for all leaks identified within five days of detection, and final repair completed within 15 days of detection (unless the delay or repair provisions are applicable). Delay of repair would be allowed where it is technically infeasible to complete repairs within 15 days without a process unit shutdown.

In addition to the monitoring and repair requirements summarized above, this proposal includes requirements for specific types of equipment. First, the EPA is proposing that each open-ended valve or line must be equipped with a closure device (*i.e.,* cap, blind flange, plug, or a second valve) that seals the open end at all times except during operations which require process fluid flow through the open-ended valve or line. Next, CVS used to comply with the standards for process unit equipment must be monitored bimonthly using OGI (or quarterly using EPA Method 21 if the alternative is used). We are also proposing that control devices used to comply with the equipment leak provisions must comply with the requirements described in section IV.G of this preamble.

The EPA is proposing that pressure relief devices must be monitored bimonthly using OGI (or quarterly using EPA Method 21 if the alternative is used) and five days after a pressure release to ensure the device has reseated after a pressure release. The proposed rule allows exceptions to the five-day post-pressure release monitoring requirement for pressure relief devices that are located in a nonfractionating plant (instead, the pressure relief device may monitored after a pressure release the next time monitoring personnel are onsite, but in no event may it be allowed to operate for more than 30 calendar days after a pressure release without monitoring) or that are routed to a process, fuel gas system or control device.

This proposed rule requires AVO, or other detection methodologies for pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service and requires repair where a leak is found using any of those methods.

Reporting would be required semiannually, which differs from the reporting for other affected facilities in NSPS OOOOb. In the initial semiannual report, the proposed rule will require the owner or operator to identify: each process unit associated with the process unit equipment affected facility; the number of each type of equipment subject to the monitoring requirements; for each month of the reporting period, the number of leaking equipment for which leaks were identified, the number of leaking equipment for which leaks were not repaired and the facts that explain each delay of repair; and dates of process unit shutdowns.

In subsequent semiannual reports, owners and operators would be required to report the name of each process unit associated with the process unit equipment affected facility; any changes to the process unit identification or the number or type of equipment subject to the monitoring requirements; for each month of the reporting period, the number of leaking equipment for which leaks were identified, the number of leaking equipment for which leaks were not repaired and the facts that explain each delay of repair; and dates of process unit shutdowns.

Required records in the proposed rule include inspection records consisting of equipment identification, date and start and end times of the monitoring inspection, inspector name, leak determination method, monitoring instrument identification, type of equipment monitored, process unit identification, appendix K records (if applicable), EPA Method 21 instrument readings and calibration results (if applicable) and, for visual inspections, the date, name of inspector and result of inspection. For each leak detected, the proposed rule requires reporting of the instrument and operator identification (or record of AVO method, where applicable), the date the leak was detected, the date and repair method applied for first attempts at repair, indication of whether the leak is still detected, and the date of successful repair, which includes results of a resurvey to verify repair. For each delay of repair, the proposed rule requires that the equipment is identified as ‘‘repair delayed’’ along with the reason for the delay, the signature of the certifying official, and the dates of process unit shutdowns which occurred while the equipment is unrepaired. Additionally, the proposed rule requires records of equipment designated for no detectable emissions; the identification of valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation stating why it is unsafe-to-monitor, and the plan for monitoring that equipment; a list of identification numbers for valves that are designated as difficult-to-monitor, an explanation stating why it is difficult-to-monitor, and the schedule for monitoring each valve; a list of identification numbers for equipment that is in vacuum service and a list of identification numbers for equipment designated as having the potential to emit methane or VOC less than 300 hr/yr. Finally, for CVS and control devices used to control emissions from process unit equipment affected facilities, the reports and records that demonstrate proper design and operation of the control device also must be maintained (see sections IV.G and IV.J. of this preamble).

2. EG OOOOc

The application of an LDAR program at an existing source is the same as at a new source because there is no need to retrofit equipment at the site to achieve compliance with the work practice standard. The cost effectiveness for implementing a bimonthly OGI LDAR program for all process unit equipment that has the potential to emit methane is approximately $850/ton methane reduced. As explained in section III.E of this preamble, the cost effectiveness of this OGI monitoring option is within the range of costs we believe to be reasonable for methane reductions in this rule. Therefore, we consider a bimonthly OGI LDAR program following appendix K that includes all process unit equipment that have the potential to emit methane to be BSER for existing sources. The presumptive standards that are proposed in this action are the same as those described above for NSPS OOOOb.

M. Sweetening Units

The EPA proposed to retain the standards found in NSPS OOOO and NSPS OOOOa for reducing SO_2 emissions from sweetening units in the November 15, 2021, proposal. The EPA is proposing regulatory text at 40 CFR 60.5405b through 60.5408b reflect the standards of performance as proposed in the November 15, 2021, proposal. To clarify and align compliance requirements (including recordkeeping and reporting) for sweetening units with those of other affected facilities, the EPA is proposing specific language at 40 CFR 60.5405b which ‘‘points’’ the owner or operator to the appropriate compliance requirement sections (*i.e.,* those containing initial compliance, continuous compliance, recordkeeping and reporting) and is proposing to enumerate the initial compliance requirements (of the unchanged standards) in section 40 CFR 60.5410b(i) and the continuous compliance requirements (of the unchanged standards) at 40 CFR 60.5415b(k).

N. Recordkeeping and Reporting

In the November 2021 proposal, the EPA proposed to require electronic reporting of performance test reports, annual reports, and semiannual reports through the Compliance and Emissions

Data Reporting Interface (CEDRI). CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). As noted in that proposal, a description of the electronic data submission process is provided in the memorandum Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules, available in the docket for this action. The EPA also proposed to allow owners and operators the ability to seek extensions for electronic reporting for circumstances beyond the control of the facility (*i.e.,* for a possible outage in CDX or CEDRI or for a *force majeure* event).

In this action, the EPA is not proposing any changes from what was proposed in the November 2021 proposal. As noted in the November 2021 proposal, owners and operators would be required to use the appropriate spreadsheet template to submit information to CEDRI for annual and semiannual reports. A draft version of the proposed templates for these reports is included in the docket for this action.[246] The EPA specifically requests comment on the content, layout, and overall design of the templates.

V. Supplemental Proposal for State, Tribal, and Federal Plan Development for Existing Sources

A. Overview

In the November 2021 proposal, the EPA proposed EG for states to follow in developing their plans to reduce emissions of GHGs (in the form of limitations on methane) from designated facilities within the Crude Oil and Natural Gas source category.[247] That proposal provided a general overview of the state planning process triggered by the EPA's finalization of EG under CAA section 111(d), the EG process and proposed state plan requirements in more detail, and solicited comment on various issues related to the EG. In this supplemental proposal, the EPA is proposing some adjustments from the November 2021 proposal, and additional requirements to provide states with information needed for purposes of state plan development. In the following sections, in the same six-part ordering as the November 2021 proposal, we summarize and rationalize the updated and new proposed requirements. The EPA is not soliciting additional comment on aspects of the November 2021 proposed EG that are not substantively addressed or changed in this supplemental proposal.

First, we discuss changes to the proposed requirements for establishing standards of performance in state plans in response to a finalized EG. Second, we discuss changes to the proposed components of an approvable state plan submission. Third, we discuss the proposed timing for state plan submissions, and changes to the proposed timeline for designated facilities to come into final compliance with the state plan. While this section describes the requirements of the implementing regulations under 40 CFR part 60, subpart Ba, proposes requirements for states in the context of this EG, and solicits comments in the context of this EG, nothing in this proposal is intended to reopen the implementing regulations themselves for comment.

B. Establishing Standards of Performance in State Plans

After the EPA establishes the BSER in the final EG, as described in preamble section XII of the November 2021 proposal and preamble section IV of this supplemental proposal, each state that includes a designated facility must develop, adopt, and submit to the EPA its state plan under CAA section 111(d). Under the Tribal Authority Rule (TAR) adopted by the EPA, tribes may seek authority to implement a plan under CAA section 111(d) in a manner similar to a state. See 40 CFR part 49, subpart A. Tribes may, but are not required to, seek approval for treatment in a manner similar to a state for purposes of developing a tribal implementation plan (TIP) implementing the EG. The November 2021 proposal included proposed requirements regarding two key aspects of implementation: establishing standards of performance for designated facilities, and providing measures that implement and enforce such standards. The November 2021 proposal additionally discussed and solicited comments on accommodating state programs, remaining useful life and other factors (RULOF), emissions inventories, and meaningful engagement. In the subsections below, the EPA proposes updates to certain presumptive standards included in the November 2021 proposal, and further proposes requirements related to leveraging state programs, RULOF, certain implementation and enforcement measures, emissions inventories, and meaningful engagement with pertinent stakeholders. The EPA believes these proposed requirements, in addition to those described in the November 2021 proposal, will be necessary for states to prepare their CAA section 111(d) state plans. The EPA is not reopening for comment any aspect described in the November 2021 proposal that the EPA is not proposing to substantively address or update in this supplemental proposal.

The November 2021 proposal included proposed requirements regarding two key aspects of implementation: establishing standards of performance for designated facilities and providing measures that implement and enforce such standards. The November 2021 proposal additionally discussed and solicited comments on accommodating state programs, RULOF, emissions inventories, and meaningful engagement. In the following subsections, the EPA proposes updates to certain presumptive standards included in the November 2021 proposal, and further proposes requirements related to leveraging state programs, RULOF, certain implementation and enforcement measures, emissions inventories, and meaningful engagement with pertinent stakeholders. The EPA believes these proposed requirements, in addition to those described in the November 2021 proposal, will be necessary for states to prepare their CAA section 111(d) state plans. The EPA is not reopening for comment any aspect described in the November 2021 proposal that the EPA is not proposing to substantively address or update in this supplemental proposal.

1. Establish Standards of Performance for Designated Facilities

In the November 2021 proposal, the EPA proposed the degree of emission limitation achievable through application of the BSER in the form of presumptive standards for designated facilities.[248] The EPA described that there is a fundamental requirement under CAA section 111(d) that a state plan's standards of performance reflect the presumptive standard, which derives from the definition of ''standard of performance'' in CAA section 111(a)(1). The EPA is updating Tables 35 and 36 to reflect the updated presumptive standards in this supplemental proposal.

[246] See Part_60_Subpart_OOOOb_60.5420b(b)_Annual_Report.xlsm and Part_60_Subpart_OOOOb_60.5422b(b)_Semiannual_Report.xlsx, available in the docket for this action.

[247] See 86 FR 63110 (November 15, 2021).

[248] 86 FR 63249 (November 15, 2021).

[249] As described in section IV.C of this preamble, the EPA is proposing a super-emitter response program under the statutory rationale that super-emitters are a designated facility. The EPA is also proposing the program under a second rationale that the super-emitter response program constitutes work practice standards for certain sources and compliance assurance measures for other sources. Under either rationale, state plans are required to

TABLE 35—SUMMARY OF PROPOSED EG SUBPART OOOOc PRESUMPTIVE NUMERICAL STANDARDS

Designated facility	Proposed presumptive numerical standards in the draft emissions guidelines for GHGs
Storage Vessels: Tank Battery with PTE of 20 tpy or More of Methane	95 percent reduction of methane.
Pneumatic Controllers: Natural gas-driven that Vent to the Atmosphere	Methane emission rate of zero.
Pneumatic Pumps	Methane emission rate of zero.
Wet Seal Centrifugal Compressors (except for those located at well sites).	Volumetric flow rate of 3 scfm.
Dry Seal Centrifugal Compressors (except for those located at well sites)	Volumetric flow rate of 3 scfm.
Reciprocating Compressors (except for those located at well sites)	Volumetric flow rate of 2 scfm.

TABLE 36—SUMMARY OF PROPOSED EG SUBPART OOOOc PRESUMPTIVE NON–NUMERICAL STANDARDS

Designated facility	Proposed presumptive non-numerical standards in the draft emissions guidelines for GHGs
Super-Emitters	Root cause analysis and corrective action following notification by an EPA-approved entity or regulatory authority of a super-emitter emissions event.[249]
Fugitive Emissions: Single Wellhead Only Well Sites and Small Well Sites.	Quarterly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Multi-wellhead Only Well Sites (2 or more wellheads)	Quarterly AVO inspections. Repair for indications of potential leaks within 15 days of inspection. Semiannual OGI monitoring (Optional semiannual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Well Sites and Centralized Production Facilities	Well sites with specified major production and processing equipment: Quarterly OGI monitoring. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt. Fugitive monitoring continues for all well sites until the site has been closed, including plugging the wells at the site and submitting a well closure report.
Fugitive Emissions: Compressor Stations	Monthly AVO monitoring. AND Quarterly OGI monitoring. (Optional quarterly EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations on Alaska North Slope.	Annual OGI monitoring. (Optional annual EPA Method 21 monitoring with 500 ppm defined as a leak). First attempt at repair within 30 days of finding fugitive emissions. Final repair within 30 days of first attempt.
Fugitive Emissions: Well Sites and Compressor Stations	(Optional) Alternative periodic screening with advanced measurement technology instead of OGI monitoring.
Fugitive Emissions: Well Sites and Compressor Stations	(Optional) Alternative continuous monitoring system instead of OGI monitoring.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—continuous bleed natural gas-driven).	Natural gas bleed rate no greater than 6 scfh.
Pneumatic Controllers: Alaska (at sites where onsite power is not available—intermittent natural gas-driven).	OGI monitoring and repair of emissions from controller malfunctions.
Gas Well Liquids Unloading	Perform liquids unloading with zero methane or VOC emissions. If this is not feasible for safety or technical reasons, employ best management practices to minimize venting of emissions to the maximum extent possible.
Equipment Leaks at Natural Gas Processing Plants	LDAR with OGI following procedures in appendix K.

adopt the super-emitter response program either as presumptive standards or as measures that provide for the implementation and enforcement of such standards.

TABLE 36—SUMMARY OF PROPOSED EG SUBPART OOOOc PRESUMPTIVE NON–NUMERICAL STANDARDS—Continued

Designated facility	Proposed presumptive non-numerical standards in the draft emissions guidelines for GHGs
Oil Wells with Associated Gas	Route associated gas to a sales line. If access to a sales line is not available, the gas can be used as an onsite fuel source or used for another useful purpose that a purchased fuel or raw material would serve. If demonstrated that a sales line and beneficial uses are not technically feasible, the gas can be routed to a flare or other control device that achieves at least 95 percent reduction in methane emissions.

2. Leveraging State Programs

a. Overview

In the November 2021 proposal, the EPA acknowledged that many states have programs they may want to leverage for purposes of satisfying their CAA section 111(d) state plan obligations (86 FR 63252; November 21, 2021). The EPA proposed that a state plan which relies on a state program must establish standards of performance that are in the same form as the presumptive standards. The EPA further solicited comment on whether states relying on state programs should be authorized to include a different form of standard in their plans so long as they demonstrate the equivalency of such standards to the level of stringency required under the final EG, and how such equivalency demonstrations can be made in a rigorous and consistent way.

The EPA also proposed to require that, in situations where a state wishes to rely on state programs (statutes and/or regulations) that pre-date finalization of the EG proposed in this document to satisfy the requirements of CAA section 111(d), the state plan should identify which aspects of the state programs are being submitted for approval as federally enforceable requirements under the plan, and include a detailed explanation and analysis of how the relied upon state programs are at least as stringent as the requirements of the final EG. The EPA noted that the completeness criteria in 40 CFR 60.27a(g) requires a copy of the actual state law/regulation or document submitted for approval and incorporation into the state plan. Put another way, where a state is relying on a state program for its plan, a copy of the pre-existing state statute or regulation underpinning the program would be required by this criterion and would be a critical component of the EPA's evaluation of the approvability of the plan. The EPA solicited comment on various ways in which state programs can be adopted into state plans particularly in situations where state programs that regulate both designated facilities and sources not considered as designated facilities under this EG could be tailored for a state plan to meet the requirements of CAA section 111(d).

The EPA believes that for states to successfully leverage their state programs to satisfy their CAA section 111(d) state plan obligations, specific criteria need to be identified for states and the EPA to follow in determining that a state plan meets the level of stringency required under the final EG, and how such equivalency demonstrations can be made in a rigorous and consistent way. The EPA is proposing such criteria for a source-by-source equivalency determination in this supplemental proposal.

Some commenters requested that the EPA make an equivalency determination on a programmatic, rather than source-specific basis. Some of these commenters suggested that the EPA approve plans that are as stringent as EG even if they do not include identical standards or sources.[250] Commenters also suggested that the EPA allow states to include a different form of numerical standard as long as it is determined to be equivalent.[251] In addition to the suggestion provided, some commenters argued that the EPA is not authorized to approve state limitations that were not derived using CAA section 111(d) standard setting methods.

The following sections discuss EPA's proposal for how states with programs that regulate GHGs in the form of methane from oil and natural gas sources may establish source-by-source equivalency with the EPA's designated facility presumptive standards under EG OOOOc. Consistent with that discussion, the EPA is also proposing to interpret CAA section 111 to authorize states to establish standards of performance for their sources that, in the aggregate, would be equivalent to the presumptive standards. The 2019 Affordable Clean Energy (ACE) Rule interpreted CAA section 111 to require that each state establish for each source a standard of performance that reduces that source's emissions, and to preclude the type of compliance flexibility that the EPA is now proposing. 84 FR 32556–57 (July 8, 2019). In 2021, the D.C. Circuit vacated the ACE Rule, holding, among other things, that CAA section 111(d) does not preclude states from allowing certain compliance flexibilities, including trading or averaging of emission limits. *American Lung Ass'n* v. *EPA,* 985 F.3d 914, 957–58 (D.C. Cir. 2021). In 2022, the U.S. Supreme Court reversed the D.C. Circuit's judgment regarding the ACE Rule's embedded repeal of the Clean Power Plan on other grounds. *West Virginia* v. *EPA,* 142 S. Ct. 2587 (2022). The Supreme Court made clear that CAA section 111 authorizes the EPA to determine the BSER and the amount of emission limitation that state plans must achieve, *id.* at 2601–02, but the Supreme Court did not address the D.C. Circuit's interpretation of CAA section 111 as to the state's compliance flexibilities. *Id.* at 2615–16.

The EPA has reconsidered the ACE Rule's interpretation of CAA section 111, and now disagrees with it. Section 111(d) does not, by its terms, preclude states from having flexibility in determining which measures will best achieve compliance with the EPA's emission guidelines. Such flexibility is consistent with the framework of cooperative federalism that CAA section 111(d) establishes, which vests states with substantial discretion. CAA section 111(d) thus permits each state, when appropriate, to adopt measures that allow its sources to meet their emission limits in the aggregate. In addition, the EPA agrees with the separate set of reasons that the D.C. Circuit gave in holding that CAA section 111(d) does not preclude a state from allowing its sources compliance flexibilities. *American Lung Ass'n* v. *EPA,* 985 F.3d 914, 957–58. Thus, it is the EPA's

[250] See Docket ID Nos. EPA–HQ–OAR–2021–0317–0581, EPA–HQ–OAR–2021–0317–0775, EPA–HQ–OAR–2021–0317–0926, and EPA–HQ–OAR–2021–0317–1267.

[251] See Docket ID Nos. EPA–HQ–OAR–2021–0317–0558, EPA–HQ–OAR–2021–0317–0761, EPA–HQ–OAR–2021–0317–0769, and EPA–HQ–OAR–2021–0317–1267.

position that CAA section 111(d) authorizes the EPA to allow states, in particular rules, to achieve the requisite emission limitation through the aggregate reductions from their sources, and the EPA is accordingly proposing to authorize states to leverage their state programs to satisfy their CAA section 111(d) state plan obligations pursuant to EG OOOOc, subject to requirements discussed in the following sections.

The EPA intends shortly to propose revisions to the implementing regulations for CAA section 111(d) at 40 CFR part 60, subpart Ba. The EPA intends, in that rulemaking, to further clarify that CAA section 111(d) and the implementing regulations authorize the EPA to, in particular rules, allow states flexibility and discretion in establishing standards of performance that meet the emission guidelines, including standards that permit their sources to comply via methods such as trading or averaging. The EPA encourages interested persons to submit comments on this issue in that rulemaking for the implementing regulations, and the EPA intends to finalize that rulemaking before finalizing this oil and gas rulemaking.

b. Types of Equivalency Evaluations

For purposes of this supplemental proposal, the EPA contemplated two types of equivalency evaluations that could be considered when comparing state programs against the stringency of EG OOOOc. These include: (1) Total program evaluation, and (2) source-by-source evaluation.

i. Total Program Evaluation

The first type of equivalency evaluation the EPA assessed is a total program evaluation, meaning assessing reductions and controls across all or different designated facilities. A total program evaluation could entail that some sources would get more reductions than the presumptive standards in the EG and others less reductions, but overall reductions are equal or greater than what would be achieved in the aggregate across all designated facilities by implementing the presumptive standards. A total program evaluation may look different for states that have designated facilities in the production, processing, and transmission and storage segments compared to states that only have designated facilities in the transmission and storage segment. The EPA recognizes that potentially allowing for total program equivalency could, in theory, reduce burden on states by allowing states with programs to rely more on those programs for their state plan submittal without needing to revise standards for specific designated facilities in order to match the presumptive standards. Furthermore, the EPA recognizes that burden may be reduced for owners and operators of designated facilities because they would not have to comply with two different sets of regulations. However, the EPA has identified the following challenges and complexities that are unique to the Crude Oil and Natural Gas source category and is therefore proposing to disallow state plans from using total program equivalence to meet the requirements of a final OOOOc EG.

One such consideration is that state programs may include sources that are not designated facilities. For example, New Mexico, Pennsylvania, and Ohio have state standards for pigging activities. The EPA is not proposing to determine a BSER or presumptive standards for pigging activities in this supplemental proposal. Because CAA section 111(d)(1) only provides that state plans may include standards of performance and certain other requirements for designated facilities, the EPA interprets the statute as not allowing the EPA to approve, and thereby render federally enforceable, state plan requirements that extend to sources that are not designated facilities. Therefore, it is not appropriate to allow a state to account for non-designated facilities as part of their state plan submission for any purpose, including for demonstrating program equivalency, even if a state regulates such sources as a matter of state law.[252]

In addition, the EPA also interprets CAA section 111(d) as not allowing the EPA to approve state plan requirements for different pollutants than those designated pollutants that are regulated in the EG. The EPA is aware that while numerous states have programs in place that regulate emissions from the designated facilities that the EPA is proposing presumptive standards for, many of those programs do not regulate GHGs in the form of limitations on methane.

The EPA also proposed in the November 2021 proposal that states are generally expected to establish the same non-numerical standards and if a state chooses to utilize a different design, equipment, work practice, and/or operational standard then the state must include in its plan a demonstration of equivalency that is consistent with alternative means of emissions limitations (AMEL) provisions. Some state commenters agreed with the EPA that states are expected to establish the same non-numerical standards.[253] The EPA recognizes if a state sought to utilize a different design, equipment, work practice, and/or operational standard, a demonstration of equivalency that is consistent with AMEL provisions would likely be technically difficult because many of the presumptive standards in the EG OOOOc are work practice standards that do not quantify emissions. This would suggest that the equivalency evaluation would need to be a qualitative analysis rather than a quantitative analysis because not all states have comprehensive source and source-specific emissions inventory data to base a stringency comparison on emissions reductions alone. The EPA believes this qualitative comparison would be extremely complicated on a holistic total program basis given that there are nine types of designated facilities with proposed presumptive standards, of which, five have numerical limits and two are in the format of work practice standards. Without a clear structure for this evaluation to address the complexities of the Crude Oil and Natural Gas source category, the EPA is concerned that emission reductions and controls consistent with the EG, and consistency of implementation across state plans, would be compromised. Similarly, the EPA proposed that for designated facilities with numerical presumptive standards, states are expected to establish the same form of numerical standards, but the EPA also took comment on whether to allow states to include a different form of numerical standards for these facilities so long as states demonstrate equivalency. Some state commenters suggested that the ability to include a different form of numerical standard in state plans is consistent with the cooperative federalism structure of CAA section 111(d).[254] While states asked for this flexibility, state commenters did not clearly provide specific examples of where a state already has a different form of a numerical standard that would necessitate this flexibility. The EPA is also concerned that there may be insufficient state comprehensive source and source-specific emissions inventory data to make the requisite technical evaluation.

[252] The EPA acknowledges that states may choose to regulate non-designated facilities under state law for other purposes than to satisfy their CAA section 111(d) state plan submission.

[253] See Docket ID No. EPA–HQ–OAR–2021–0317–1267.

[254] See Docket ID No. EPA–HQ–OAR–2021–0317–1267.

Another complicating scenario informing the EPA's proposal to disallow total program equivalence is that there are instances where a state covers part or subset of the EG designated facility's applicability definitions. For example, Colorado requires the use of non-emitting[255] pneumatic controllers with specific exceptions. One exception is that operators do not have to retrofit their controllers to become non-emitting if on a company-wide basis, the average production from producing wells in 2019 is less than 15 barrel of oil equivalent/day/well. However, the EPA's supplemental proposal for pneumatic controllers, as discussed in section VII.D of this preamble, proposes a methane emission rate of zero with no applicability site wide production or other threshold thus covering a broader group of pneumatic controllers. If the EPA were to permit total program equivalence where state programs do not align with the EG, then there could be situations where a state would be allowed to forgo regulating some designated facilities that the EPA has determined are reasonable to control.

For these reasons and the critical need to provide clear regulatory certainty to the hundreds of thousands of designated facilities in this uniquely large source category, the EPA does not think a total program evaluation would guarantee that the same emissions reductions as required by the EG would be achieved. The EPA solicits comments on how a total program evaluation could be established in a way that would address the complexities of the Crude Oil and Natural Gas source category and concerns the EPA has identified.

[255] The terms ''zero emissions'' and ''non-emitting'' are used to describe pneumatic controllers. In Colorado, 5 CCR Regulation 7, Part D, Section III, defines a ''non-emitting'' controller as ''a device that monitors a process parameter such as liquid level, pressure or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to: no-bleed pneumatic controllers, electric controllers, mechanical controllers and routed pneumatic controllers.'' A routed pneumatic controller is defined as ''a pneumatic controller that releases natural gas to a process, sales line or to a combustion device instead of directly to the atmosphere.'' The EPA is proposing that pneumatic controllers must be ''zero emission'' controllers. The difference in non-emitting, as defined by Colorado and zero emissions, as proposed in this action, is that pneumatic controllers for which emissions are captured and routed to a combustion device are not considered to be ''zero emission'' controllers. Therefore, routing to a combustion device is not an option for compliance with the proposed EG OOOOc.

ii. Source-by-Source Evaluation

The second type of equivalency considered is a source-by-source evaluation for a specific designated facility, such as between all storage vessels located in a state or between a subset of centrifugal compressors. A source-by-source evaluation could entail a state conducting equivalency evaluation for one or more designated facilities and their respective presumptive standards. In theory, if a state were to do a source-by-source evaluation for each individual designated facility in its state, this could be considered a form of total program evaluation that is distinct from the type of total program evaluation described above that the EPA is proposing to disallow, where equivalence can be evaluated across different designated facilities rather than designated facilities of the same type. A source-by-source evaluation assumes that all sources in a state that meet the applicability definition for a specific designated facility (*e.g.,* pneumatic controllers, pneumatic pumps, and reciprocating compressors), would in the aggregate have to achieve the same or better reductions of the same designated pollutant as if the state instead imposed the presumptive standards required under the EG. A source-by-source evaluation, in theory, may push states to make changes to their state rules, which may increase burden on states, but is likely a more reliable way to determine that the state is achieving all emission reductions equivalent to implementing the presumptive standards. Given that state programs do vary considerably, a source-by-source evaluation would allow states to pick and choose which state standards they want to leverage for purpose of their state plan development. It is theoretically less technically difficult to evaluate equivalency on a source-by-source basis for the Crude Oil and Natural Gas source category compared to total program equivalence. The EPA is proposing five basic criteria for when states may use a source-by-source evaluation as part of their state plans (discussed in section V.B.2.b.iii of this preamble).

An example of a source-by-source stringency comparison is the comparison the EPA prepared when assessing the stringency of state fugitive emissions monitoring programs compared to what was required under NSPS OOOOa.[256] Similar to that example, the EPA proposes that any stringency comparison conducted to determine equivalence with the proposed presumptive standards that are work practices will need to be designated facility specific and the qualitative assessment will need to be tailored to ensure that the correct technical metrics are being compared.

[256] *Memorandum: Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR part 60, subpart OOOOa.* See Document ID No. EPA–HQ–OAR–2017–0483–2277.

iii. Source-by-Source Evaluation Criteria and Methodology

In order to implement a source-by-source evaluation, the EPA is proposing five basic criteria to determine whether a source-by-source evaluation can be considered for equivalency. The criteria are: (1) Designated facility, (2) designated pollutant, (3) standard type/format of standard (*e.g.,* numeric, work practice), (4) emission reductions (with consideration of applicability thresholds and exemptions), and (5) compliance assurance requirements (*e.g.,* monitoring, recordkeeping, and reporting).

In the following paragraphs, the EPA proposes a source-by-source equivalency step-by-step approach followed by an example for hypothetical state rules illustrating how states could implement the proposed approach when conducting a state rule equivalency determination with the proposed presumptive standards.

Step One. Is state rule designated facility definition, pollutant, and format the same? The first questions that a state needs to answer is whether their program defines their regulated emissions source similar to how the EPA defines a designated facility. Do their program requirements for the designated facility regulate the same pollutant, and is the format of the standard the same (*e.g.,* work practice or performance based numerical standard)? If the answer is no to any of these questions (*e.g.,* state program regulates VOC and not methane), then the state plan cannot include an equivalency determination with the EPA's proposed presumptive standards for the designated facility. If the answer is yes to all of these questions, a state would proceed to Step Two.

Step Two. Emissions Reductions. A state plan needs to include a demonstration that the state requirements for designated facilities achieve the same or greater emissions reduction as the designated facility presumptive standards. A state would have several options to make this demonstration.

The first option would be to make a demonstration that the designated facility state standard achieves the same emission reduction as the designated facility BSER analysis using the EPA model plant/representative facility. The second option would be to make a demonstration that the designated facility state standard achieves the same or greater emissions reduction ''in real life'' as the designated facility model plant/representative facility emission reduction in the BSER analysis. The third option would be that a state could apply the designated facility presumptive standard to ''real life'' (*e.g.,* using activity (number of sources) and actual emissions data) and calculate the state-wide emission reduction that would be achieved, and then demonstrate that the state program requirements for a designated facility would achieve the same or greater emissions reduction. If emissions reductions from the implementation of the state rule are less than would be achieved from the implementation of the presumptive standards, the state cannot make an equivalency determination with the EPA's proposed presumptive standards. If emissions reductions from the implementation of the state rule are the same or greater than would be achieved from the implementation of the presumptive standards, a state would proceed to Step Three.

Step Three. Make demonstration that compliance measures included for a designated facility under a state program are at least as effective as those in the presumptive standard. Once a state has determined that the emission reductions from the implementation of the state requirements for a designated facility are the same or greater than would be achieved by the implementation of the presumptive standards for a designated facility under Step Two, a state plan would need to include a demonstration that compliance measures (*e.g.,* monitoring, recordkeeping and reporting requirements) are sufficient to ensure continued compliance with the standards and projected emission reductions.

Centrifugal Compressor Examples—Comparison of Primary Presumptive Standards With 4 Hypothetical Examples.

Table 37 provides examples of the application of the steps outlined above for five hypothetical state rules for reciprocating compressors at gathering and boosting stations in the production segment. The parameters for the presumptive standard for reciprocating compressors are as follows.

(1) The designated facility is a single reciprocating compressor.

(2) The designated pollutant is methane, using volumetric flow rate as a surrogate for methane).

(3) The standard type/format of standard is a numerical standard (2 scfm volumetric flow rate).

(4) The estimated methane emission reductions for the model compressor in the BSER analysis for the presumptive standard was 92 percent reduction.

(5) The compliance assurance requirements include the requirement to measure the flow rate once every 8,760 operating hours and maintain records.

TABLE 37—RECIPROCATING COMPRESSOR DESIGNATED FACILITY PRESUMPTIVE STANDARDS EQUIVALENCY EVALUATION EXAMPLES

Designated facility requirements	Equivalency determination steps		
	Step one—applicability and format of standard	Step two—emission reduction	Step three—compliance assurance measures
Example A:			
Designated Facility: Single Reciprocating Compressor at Gathering and Boosting.	FAIL—format of standard not equivalent.		
Designated Pollutant: Methane.			
Format of Standard: Work Practice (Change out rod packing every 3 years).			
Estimated Emission Reduction (Basis): 56% (model compressor basis).			
Compliance Assurance Requirements: Records of changeout.			
Example B:			
Designated Facility: Single Reciprocating Compressor at Gathering and Boosting.	PASS	PASS	PASS.
Designated Pollutant: Total hydrocarbon as Surrogate for Methane.			
Format of Standard: Numerical (Collect and route to control to achieve 95% reduction).			
Estimated Emission Reduction (Basis): 95% (model compressor basis).			
Compliance Assurance Requirements: Performance test of control device, continuous parameter monitoring, recordkeeping and reporting.			
Example C:			
Designated Facility: Single Reciprocating Compressor at Gathering and Boosting.	FAIL—format of standard not equivalent.		
Designated Pollutant: Total Gas Flow rate as surrogate for methane.			
Format of Standard: Directed Inspection and Maintenance (Measure flow rate annually and replace or repair if volumetric flow is greater than 3 scfm).			
Estimated Emission Reduction (Basis): 92% (model compressor basis).			

TABLE 37—RECIPROCATING COMPRESSOR DESIGNATED FACILITY PRESUMPTIVE STANDARDS EQUIVALENCY EVALUATION EXAMPLES—Continued

Designated facility requirements	Equivalency determination steps		
	Step one—applicability and format of standard	Step two—emission reduction	Step three—compliance assurance measures
Compliance Assurance Requirements: Records of measurements, records of corrective actions if greater than 3 scfm, records of new measurement to demonstrate less than 3 scfm after corrective action.			
Example D:			
Designated Facility: Single Reciprocating Compressor at Gathering and Boosting.			
Designated Pollutant: Total gas flow rate as surrogate for methane.			
Format of Standard: Numerical: 5 scfm.			
Estimated Emission Reduction (Basis): using analysis of state-wide emissions from actual reciprocating compressors, estimated that presumptive standard would achieve 85% reduction over the state, state rule would achieve 87% reduction..			
Compliance Assurance Requirements: Measure volumetric flow rate once every six months, record results..	PASS	PASS Demonstrated that the "real life" state-wide emission reduction for state rule was greater than the "real-life" reduction for the presumptive standard..	PASS.
Example E:			
Designated Facility: Single Reciprocating Compressor at Gathering and Boosting.	PASS	FAIL—did not demonstrate that the BSER presumptive standard model facility reduction was met.	
Designated Pollutant: Total gas flow rate as surrogate for methane.			
Format of Standard: Numerical: 4 scfm.			
Estimated Emission Reduction (Basis): 88% (analysis of state-wide emissions from actual reciprocating compressors).			
Compliance Assurance Requirements: Measure volumetric flow rate once every six months, record results.			

The EPA solicits comment on the EPA's proposed state program equivalency demonstration methodology and evaluating criteria for when state plans may include standards of performance based on an equivalency demonstration. Specifically, the EPA solicits comments on other criteria than what the EPA is proposing should be considered; and whether there are other additional qualitative factors/criteria need to be included to make an effective stringency evaluation for different types of different design, equipment, work practice, and/or operational standards.

c. General Permitting Programs

The EPA also recognizes that some states may regulate the designated facilities proposed to be regulated under the EGs through a general permit program. For example, general permits often include standardized terms and conditions related to emissions control, compliance certification, notification, recordkeeping, reporting, and source testing requirements. The EPA is not proposing a regulatory amendment on this point but confirms that the implementing regulations under subpart Ba allows for standards of performance and other state plan requirements to be established as part of state permits and administrative orders, which are then incorporated into the state plan. See 40 CFR 60.27a(g)(2)(ii).

However, the EPA notes that the permit or administrative order alone may not be sufficient to meet the requirements of an EG or the implementing regulations, including the completeness criteria under 40 CFR 60.27a(g). For instance, a plan submission must include supporting material demonstrating the state's legal authority to implement and enforce each component of its plan, including the standards of performance. *Id.* at 40 CFR 60.27a(g)(2)(iii). In addition, EG OOOOc may also require demonstrations that may not be satisfied by terms of a permit or administrative order. To the extent that these and other requirements are not met by the terms of the incorporated permits and administrative orders, states will need to include materials in a state plan submission demonstrating how the plan meets those requirements.

3. Remaining Useful Life and Other Factors (RULOF)

Under CAA section 111(d), the EPA is required to promulgate regulations under which states submit plans establishing standards of performance for designated facilities. While states establish the standards of performance, there is a fundamental obligation under CAA section 111(d) that such standards reflect the degree of emission limitation achievable through the application of the BSER, as determined by the EPA. As previously described, this obligation derives from the definition of "standard of performance" under CAA section 111(a)(1). The EPA identifies the degree of emission limitation achievable through application of the BSER as part of its EG. 40 CFR 60.22a(b)(5).

While standards of performance must generally reflect the degree of emission limitation achievable through application of the BSER, CAA section 111(d)(1) also requires that the EPA regulations permit the states, in applying a standard of performance to a particular designated facility, to take into account the designated facility's RULOF. The EPA's implementing regulations under 40 CFR 60.24a(e) allows a state to consider a designated facility's RULOF in applying a standard of performance less stringent than the presumptive level of stringency given in an EG to a particular source, provided that the state makes the required demonstration under this provision. However, as described further below, this provision does not provide clear parameters for states on how and when to apply a standard less stringent than the presumptive level of stringency given in an EG to a particular source. The EPA intends to propose clarifying revisions to this provision under the implementing regulations in an upcoming rulemaking that would apply generally to new EG promulgated under CAA section 111(d). While inviting comments on the application of these proposed revisions in the context of the oil and gas sector in this rulemaking, the EPA also encourages the public to provide comments on these proposed revisions more generally in that upcoming rulemaking process to amend the implementing regulations. The EPA intends to finalize that rulemaking before finalizing this oil and gas rulemaking.

Consistent with its intended revisions to the implementing regulations, the EPA is proposing to supersede the current 40 CFR 60.24a(e) by providing requirements specific to EG OOOOc for the consideration of RULOF in state plans to set a less stringent standard for a particular source. The EPA notes that the EPA considers the application of the proposed RULOF provisions to apply in circumstances distinct from source-by-source evaluation discussed earlier in section V.B.2. In other words, these provisions apply where a state intends to *depart* from the presumptive standards in EG OOOOc and propose a less stringent standard for a designated facility (or class of facilities), and not where a state intends to *comply* by demonstrating that a facility or group of facilities subject to a state program would, in the aggregate, achieve equivalent or better reductions than if the state instead imposed the presumptive standards required under the EG. The EPA's proposed RULOF requirements for the application of a less stringent standard and rationale are as follows.

The RULOF provision currently under 40 CFR 60.24a(e) allows states to consider RULOF to apply a less stringent standard of performance for a designated facility or class of facilities if they demonstrate one of the three following circumstances: unreasonable cost of control resulting from plant age, location, or basic process design; physical impossibility of installing necessary control equipment; or other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable. The implementing regulations also specify that, absent such a demonstration, the state's standards of performance must be ''no less stringent than the corresponding'' EG. 40 CFR 60.24a(c). This supplemental proposal largely retains the substance of this threshold provision for purposes of EG OOOOc, including the three circumstances under which a less stringent standard of performance may be applied, and provide further clarification of what a state must demonstrate in order to invoke RULOF when submitting a state plan. Specifically, the EPA proposes to require the state to demonstrate that a particular facility cannot reasonably achieve the degree of emission limitation achievable through application of the BSER, based on one or more of the three circumstances. The EPA is also proposing to clarify the third circumstance by specifying that states may apply a less stringent standard if factors specific to the facility are fundamentally different than those considered by the EPA in determining the BSER. Subsection a. describes the statutory and regulatory background, and subsection b. explains the agency's rationale for its proposal. Subsections c-h describe further proposed additions to the RULOF provision in cases where states seek to apply a standard that is less stringent than the degree of emission limitation achievable through application of the BSER. These proposed additions include requirements for the calculation of a less stringent standard, contingency requirements in cases where an operating condition is the basis for RULOF, and the consideration of disproportionately impacted communities. Finally, subsection i. describes the proposal to address cases where states seek to apply a more stringent standard.

a. Statutory and Regulatory Background

The 1970 version of CAA section 111(d) made no reference to the consideration of RULOF in the context of standards for existing sources. In the 1975 regulations promulgating subpart B, however, the EPA included a so-called variance provision. For health-based pollutants, states could apply a standard of performance less stringent than the EPA's EGs based on cost, physical impossibility, and other factors specific to a designated facility that make the application of a less stringent standard significantly more reasonable. 40 CFR 60.24(f). For welfare-based pollutants, states could apply a less stringent standard by balancing the requirements of an EG ''against other factors of public concern.'' 40 CFR 60.24(d). As part of the 1977 CAA amendments, Congress amended CAA section 111(d)(1) to require that the EPA's regulations under this section ''shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.'' At the time, the EPA considered the variance provision under subpart B to meet this requirement and did not revise the provision subsequent to the 1977 CAA amendments until promulgating new implementing regulations in 2019 under subpart Ba. As part of the 2019 revisions, the EPA removed the health and welfare-based pollutants distinction and collapsed the associated requirements of the previous variance provision into a single, new RULOF provision under 40 CFR 60.24a(e). 84 FR 32520, 32570. The D.C. Circuit vacated several timing-related provisions under 40 CFR part 60, subpart Ba; however, Petitioners did not challenge, and the court did not vacate, the new RULOF provision under 40 CFR 60.24a(e). *Am. Lung Assoc.* v. *EPA,* 985 F.3d at 991 (D.C. Cir. 2021) (*ALA*).[257]

b. Rationale for the Proposed Revisions

As previously described, the statute expressly requires the EPA to permit states to consider RULOF for a particular designated facility when applying a standard of performance to that facility. The consideration of remaining useful life in particular can be an important consideration, as the cost of control for a specific designated facility that is not expected to operate in the long term, relative to other designated facilities in the source category, could significantly vary from the average cost calculations done as part of the BSER determination for the source category as a whole. In such an instance, and in others as described throughout this section, a less stringent standard may be more reasonable to

[257] The Supreme Court subsequently reversed and remanded the D.C. Circuit's opinion. *West Virginia* v. *EPA,* 142 S.Ct. 2587 (June 30, 2022). However, no Petitioner sought certiorari on, and the *West Virginia* decision did not implicate, the D.C. Circuit's vacatur of portions of subpart Ba.

apply than a standard of performance that reflects the presumptive level of stringency.

In order to understand how states may have dealt with this issue in their programs, the EPA examined several existing state oil and natural gas regulations and programs. Based on our examination, we did not identify any provision in any of the state oil and natural gas regulations that included a less stringent standard for equipment or operations with a shortened lifespan. The EPA is interested in obtaining information on whether this situation exists in state oil and natural gas rules that we may not have identified in our search. In addition, the EPA is soliciting comment on situations where state rules for industries other than the oil and natural gas industry include less stringent requirements for sources that are soon to retire. If these situations exist, the EPA is not only interested in the less stringent requirements as they compare to the ''normal'' standards, but also how the state evaluated the suitability of the less stringent requirements.

As currently written, the RULOF provision in subpart Ba does not provide clear parameters for states on how and when to apply a standard less stringent than the presumptive level of stringency given in an EG to a particular source. As written, the references to reasonableness in this provision are potentially subject to widely differing interpretations and inconsistent application among states developing plans, and by the EPA in reviewing them. Without a clear analytical framework for applying RULOF, the current provision may be used by states to set less stringent standards that could effectively undermine the overall presumptive level of stringency envisioned by the EPA's BSER determination and render it meaningless.[258] Such a result is contrary to the overarching purpose of CAA section 111(d), which is generally to require meaningful emission reductions from designated facilities based on the BSER.

Additionally, while states have discretion to consider RULOF under CAA section 111(d), it is the EPA's responsibility to determine whether a state plan is ''satisfactory,'' [259] which includes evaluating whether RULOF was appropriately considered. The relevant dictionary meaning of ''satisfactory'' is ''fulfilling all demands or requirements.'' The American College Dictionary 1078 (C.L. Barnhart, ed. 1970). Thus, the most reasonable interpretation of a ''satisfactory plan'' is a CAA section 111(d) plan that meets the applicable conditions or requirements, including those under the implementing regulations that the EPA is directed to promulgate pursuant to CAA section 111(d), including the provisions governing the application of RULOF.[260]

The EPA's determination of whether each plan is ''satisfactory'', including the application of RULOF, must be generally consistent from one plan to another. If the states do not have clear parameters for how to consider RULOF when applying a standard of performance to a designated facility, then they face the risk of submitting plans that the EPA may not be able to consistently approve as satisfactory. For example, under the current broadly structured provision, two states could consider RULOF for two identically situated designated facilities and apply completely different standards of performance on the basis of the same factors. In this example, it may be difficult for the EPA to substantiate finding both plans satisfactory in a consistent manner, and the states and sources risk uncertainty as to whether each of the differing standards of performance would be approvable. Accordingly, providing a clear analytical framework for EG OOOOc for the invocation of RULOF will provide regulatory certainty for states and the regulated community as they seek to craft satisfactory plans that the EPA can ultimately approve.

For these reasons, the EPA is proposing the RULOF provision under subpart OOOOc, consistent with the statutory construct and goals of CAA section 111(d), in order to provide states and sources with clarity regarding the requirements that apply to the development and approvability of state plans that consider RULOF when applying a standard of performance to a particular designated facility. Below, we describe the guiding principles for the EPA's proposed revisions.

CAA section 111(a)(1) requires that the EPA determine the BSER is ''adequately demonstrated'' for the regulated source category. In determining whether a given system of emission reduction qualifies as BSER, CAA section 111(a)(1) requires that the EPA take into account ''the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements.'' The EPA's proposed RULOF provision does so by tethering the states' RULOF demonstration to the statutory factors the EPA considered in the BSER determination. This is appropriate under the statute because the EPA will have demonstrated that the BSER identified in EG OOOOc is ''adequately demonstrated'' as achievable for sources broadly within the Crude Oil and Natural Gas source category. Therefore, RULOF is appropriately applied to permit states to address instances where the application of the BSER factors to a particular designated facility is fundamentally different than the determinations made to support the BSER and presumptive level of stringency in the EG. For example, the D.C. Circuit has stated that to be ''adequately demonstrated,'' the system must be ''reasonably reliable, reasonably efficient, and . . . reasonably expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' *Essex Chem. Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973). The court has further stated that the EPA may not adopt a standard in evaluating cost that would be ''exorbitant,'' [261] ''greater than the industry could bear and survive,'' [262] ''excessive,'' [263] or ''unreasonable.'' [264] These formulations use reasonableness

[258] CAA section 111(d) does not require states to consider RULOF, but rather requires that the EPA's regulations ''permit'' states to do so. In other words, the EPA must provide states with the ability to account for RULOF, but states may instead choose to establish a standard of performance that is the same as the presumptive level of stringency set forth in the EGs. The optionality, rather than mandate, for states to account for RULOF supports the notion that this provision is not intended to undermine the presumptive level of stringency in an EG for the source category broadly. Additionally, the EPA notes that it is not aware of any CAA section 111(d) EGs under which an EPA-approved state plan has previously considered RULOF to apply a standard of performance that deviates from the presumptive level of stringency. Clarifying parameters may better enable states to effectively use this provision in developing their state plans.

[259] CAA section 111(d)(2)(A) authorizes the EPA to promulgate a Federal plan for any state that ''fails to submit a satisfactory plan'' establishing standards of performance under CAA section 111(d)(1). Accordingly, the EPA interprets ''satisfactory'' as the standard by which the EPA reviews state plan submissions.

[260] Although there is no case law specifically on the standard of review of a CAA section 111(d)(1) state plan or the EPA's duty to approve satisfactory plans, the EPA's action on a CAA section 111(d)(1) state plan is structurally identical to the EPA's action on a state implementation plan (SIP). Under section 110(k)(3), EPA must approve a SIP that meets all requirements of the Act. *See Train* v. *NRDC,* 421 U.S. 60 (1975) (discussing the 1970 version of the Act); *Virginia* v. *EPA,* 108 F.3d 1397, 1408–10 (D.C. Cir. 1995) (discussing the 1970, 1977, and 1990 versions).

[261] *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

[262] *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975).

[263] *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981).

[264] *Ibid.*

in light of the statutory factors as the standard in evaluating cost, so that a control technology may be considered the ''best system of emission reduction . . . adequately demonstrated'' if its costs are reasonable (*i.e.,* not exorbitant, excessive, or greater than the industry can bear), but cannot be considered the BSER if its costs are unreasonable. Similarly, in making the BSER determination, the EPA must evaluate whether a system of emission reduction is ''adequately demonstrated'' for the source category based on the physical possibility and technical feasibility of control. Under this construct, it naturally follows that most designated facilities within the source category should be able to implement the BSER at a reasonable cost to achieve the presumptive level of stringency, and RULOF will be applicable only for a subset of sources for which implementing the BSER would impose unreasonable costs or not be feasible due to unusual circumstances that are not applicable to the broader source category that the EPA considered when determining the BSER.[265]

The RULOF provision we are proposing in this rule is consistent with how the EPA has approached RULOF in the implementing regulations previously. Subparts B and Ba both currently contain the same three circumstances for when states may account for RULOF, and reasonableness in light of the statutory criteria is an element of all three circumstances. Under those subparts as currently written, states may consider RULOF if they can demonstrate unreasonable cost of control, physical impossibility of control, or other factors that make application of a less stringent standard ''significantly more reasonable.'' 40 CFR 60.24(f), 40 CFR 60.24a(e). The EPA's proposal for EG OOOOc retains the first circumstance in whole and revises the second one to add ''technical infeasibility'' of installing a control as a situation where application of consideration of RULOF may be appropriate. The proposal for EG OOOOc further clarifies the third catch-all circumstance, which the first two circumstances also fall under, by specifying that states may consider RULOF to apply a less stringent standard if factors specific to a designated facility are fundamentally different from the factors considered in the determination of the BSER in EG OOOOc. The proposed third criteria provides parameters for states and the EPA in developing and assessing state plans, as this criterion was previously vague in the implementing regulations and potentially open-ended as to the circumstances under which states could consider RULOF.

The ''fundamentally different'' standard, which undergirds all three circumstances, is also consistent with other variance provisions that courts have upheld for environmental statutes. For example, in *Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011 (D.C. Cir. 1978), the D.C. Circuit considered a regulatory provision promulgated under the Clean Water Act (CWA) that permitted owners to seek a variance from the EPA's national effluent limitation guidelines under CWA sections 301(b)(1)(A) and 304(b)(1). The EPA's regulation permitted a variance where an individual operator demonstrates a ''fundamental difference'' between a CWA section 304(b)(1)(B) factor at its facility and the EPA's regulatory findings about the factor ''on a national basis.'' *Id.* at 1039. The court upheld this standard as ensuring a meaningful opportunity for an operator to seek dispensation from a limitation that would demand more of the individual facility than of the industry generally, but also noted that such a provision is not a license for avoidance of the Act's strict pollution control requirements. *Id.* at 1035.

For the reasons described in this section, the EPA is proposing RULOF provisions for purposes of EG OOOOc by: (1) Including the threshold requirements for consideration of RULOF; (2) adding requirements for calculating a less stringent standard accounting for RULOF; (3) adding requirements for consideration of communities most affected by and vulnerable to the health and environmental impacts from the designated facilities being addressed; and (4) adding requirements for the types of information and evidence the states must provide to support the invocation of RULOF in a state plan. The EPA solicits comment on the proposed provisions described in the following subsections, including the use of the BSER as a central tenet governing the invocation of the RULOF provision.

The EPA also solicits comment about whether, instead of establishing firm requirements for the application of RULOF, the EPA should instead consider establishing a framework, consistent with the proposed requirements in the following discussion, pursuant to which state plans would be considered presumptively approvable. In this scenario, states would have certainty regarding what type of demonstration the EPA would find satisfactory as they develop their plans, but states could also submit an alternative RULOF demonstration for the EPA's consideration. In the latter case, states would bear the burden of proving to the EPA that they have proposed a satisfactory alterative analysis and standard, considering all factors relevant to addressing emissions from the source or sources at issue. The EPA also solicits comment on what different approaches might be appropriate for a state in applying RULOF to a particular source and that the EPA should consider in determining whether to finalize the provisions discussed below, either as requirements or as presumptions.

c. Threshold Requirements for Considering Remaining Useful Life and Other Factors

Under the existing RULOF provision in subpart Ba, 40 CFR 60.24a(e), a state may only account for RULOF in applying a standard of performance provided that it makes a demonstration based on one of three criteria. These criteria are: (1) Unreasonable cost of control resulting from plant age, location, or basic process design; (2) physical impossibility of installing necessary control equipment; or (3) other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable. But the existing version of this provision in subpart Ba provides no further guidance on what constitutes reasonableness or unreasonableness for these demonstrations. The EPA proposes this provision and clarifies it for purposes of EG OOOOc to require that in order to account for RULOF in applying a less stringent standard of performance to a designated facility, a state must demonstrate that the designated facility cannot reasonably apply the BSER to achieve the degree of emission limitation determined by the EPA because it entails: (1) An unreasonable cost of control resulting from plant age, location, or basic process design; (2) physical impossibility or technical infeasibility of installing necessary control equipment; or (3) other factors specific

[265] This construct is also supported by CAA section 111(d) use of the term ''establishing'' in directing states to create and set standards of performance. As previously described, ''standard of performance'' is defined under CAA section 111(a)(1) as reflecting the degree of emission limitation achievable through application of the BSER, which sets the initial parameters for development of the standards of performance by states. The statute does not provide that states may account for RULOF in ''establishing'' standards of performance in the first instance, but permits states to do so in ''applying'' such standards to a particular source.

to the facility (or class of facilities) that are fundamentally different from the factors considered in the establishment of the emission guidelines.[266] The EPA proposes in EG OOOOc that the first criterion remains the same as under the existing RULOF provision in 40 CFR 60.24a(e). For the second criterion, the EPA is proposing in EG OOOOc to add a reference to technical infeasibility, as a similar yet distinct factor from that of physical impossibility of control. Finally, the EPA is proposing in EG OOOOc to revise the third criterion to capture any circumstance at a specific designated facility that is fundamentally different from the factors the EPA considered in determining the BSER.

The EPA proposes in EG OOOOc to require that, in order to demonstrate that a designated facility cannot reasonably meet the presumptive level of stringency based on one of these three criteria, the state must show that implementing the BSER is not reasonable for the designated facility due to fundamental differences between the factors the EPA considered in determining the BSER, such as cost and technical feasibility of control, and circumstances at the designated facility. Per the requirements of CAA section 111(a)(1), the EPA determines the BSER by first identifying control methods that it considers to be adequately demonstrated, and then determining which are the best systems by evaluating (1) the cost of achieving such reduction, (2) any non-air quality health and environmental impacts, (3) energy requirements, (4) the amount of reductions, and (5) advancement of technology. Accordingly, the state plan must show that there are fundamental differences between a designated facility and the EPA's BSER determination based on the EPA's consideration of any of these factors.

For instance, if the state could demonstrate that the cost-per-ton was significantly higher at a specific designated facility than estimated by the EPA in the BSER analysis, and/or that a specific designated facility does not have adequate space to reasonably accommodate the installation, and/or that it is technically infeasible to comply with the presumptive standard based on source-specific technical barriers that are fundamentally different than those considered in the EPA's BSER determination, that designated facility may be evaluated for a less stringent standard because of the consideration of RULOF.

However, states may not invoke RULOF based on minor, non-fundamental differences. There could be instances where a designated facility may not be able to comply with the level of stringency required by EG OOOOc based on the precise metrics of the BSER determination but is able to do so within a reasonable margin. For example, the costs and cost effectiveness could be slightly higher than estimated by the EPA for the BSER for the presumptive standard, but that would not invoke RULOF. Similarly, there might also be instances where the EPA determines the BSER for a designated facility as a particular technology, but a particular designated facility does not currently have the capability to implement that technology, or it would be cost prohibitive to gain that capability. However, if that designated facility has the ability instead to reasonably install a different, non-BSER technology to achieve the presumptive level of stringency, the designated facility would not be eligible for a less stringent standard that accounts for RULOF.

Following are a few illustrative examples. The EPA is proposing to determine the BSER for wet seal centrifugal compressors designated facility an emission standard of 3 scfm volumetric flow rate. As described in section IV.G of this preamble, the cost effectiveness of complying with the 3 scfm emission standard is estimated to be approximately $711 per ton of methane reduced for compressors in the transmission and storage segment. Therefore, under the proposed RULOF requirements for this EG, the state could evaluate the cost effectiveness of implementing the BSER for a particular wet seal centrifugal compressor in order to achieve the presumptive standard. As noted above, the first criterion a state may use to justify RULOF in applying a standard of performance is unreasonable cost of control resulting from plant age, location, or basic process design. If a state determined that for a centrifugal compressor affected facility in their state, the cost effectiveness was $71,000 per ton of methane removed, that would represent a valid demonstration of unreasonable cost of control. However, a slightly higher cost effectiveness (*e.g.,* $1,000 per ton, which is well within the range the EPA deems to be cost-effective) may be representative of a minor difference that would not represent a valid demonstration for unreasonable cost. This example is only for illustrative purposes and should not be interpreted to represent the difference that must exist to demonstrate unreasonable cost of control (*i.e.,* the cost effectiveness does not need to be two orders of magnitude higher than the presumptive standard to be considered unreasonable).

By way of further example, for the pneumatic controller designated facility, the EPA determined that use of non-venting controllers is BSER. At sites without electrical power, compliance solutions include solar-powered controllers, a generator which powers electrical controllers or an instrument air system, capturing the emissions and routing them to a process, or installing self-contained controllers. There could be physical constraints that impact the installation of solar panels or a generator, and there may be technical infeasibility issues related to ability to route to a process or to use self-contained controllers. If a state determined that it would be physically impossible and technically infeasible to install non-venting controllers at a designated facility given the size and physical constraints needed to install it, the lack of a process that can accept the gas, or operational conditions that would not support the use of a self-contained controller, this would represent a valid demonstration of physical impossibility or technical infeasibility of installing necessary control equipment.

As a third example of how RULOF may not be used is in the case of the super-emitter response program. Upon notification of an emission event over 100 kg/hr, the program requires an owner/operator to do a root cause analysis to determine the source of the emissions event and either take corrective action or explain why no corrective action was warranted. Because it is not known what the source of the emissions event is prior to the root cause analysis, RULOF cannot be applied in any state plan to exempt an owner or operator from conducting this analysis. Moreover, the EPA anticipates it would generally be inappropriate for a designated facility with a less stringent standard due to RULOF to be permitted to have unintentional and continuing emissions events as high as 100 kg/hr such that the owner/operator would not need to take corrective action under the super-emitter response program.

The EPA solicits comment on the proposal to require states to demonstrate, as a threshold matter when determining whether a state may account for RULOF in order to set a less

[266] States may also account for RULOF when applying standards of performance to a class of designated facilities. For purposes of administrative efficiency, a state may be able to calculate a uniform standard of performance that accounts for RULOF using a single set of demonstrations to meet the proposed requirements described in this section if the group of sources has similar characteristics.

stringent standard, that the designated facility cannot reasonably apply the BSER to achieve the presumptive level of stringency determined by the EPA. The EPA further solicits comment on whether other considerations should inform the circumstances under which the EPA should permit RULOF to be used to set a less stringent standard for a particular designated facility. The EPA also discusses and solicits comments later in section V.B.3.g. on the types of information used to support a RULOF demonstration.

d. Calculation of a Standard Which Accounts for Remaining Useful Life and Other Factors

If a state has made the proposed demonstration that accounting for RULOF is appropriate for a particular designated facility, the state may then apply a less stringent standard. The current RULOF provision in subpart Ba is silent as to how a less stringent standard should be calculated, raising the potential for inconsistent application of this provision across states and the potential for the imposition of a standard less stringent than what would be reasonably achievable by a designated facility. In order to fill this gap and ensure the integrity of EG OOOOc, the EPA is proposing several requirements that would apply for the calculation of a standard of performance that accounts for RULOF. The proposed requirements described in this section would provide a framework for the state's analysis in evaluating and identifying a less stringent standard, and in doing so would prevent the application of a standard that is less stringent than what is otherwise reasonably achievable by a particular designated facility.

The EPA is first proposing in EG OOOOc to require that the state determine and include, as part of the plan submission, a source-specific BSER for the designated facility. As described previously, the statute requires the EPA to determine the BSER by considering control methods that it considers to be adequately demonstrated, and then determining which are the best systems by evaluating: (1) The cost of achieving such reduction, (2) any non-air quality health and environmental impacts, (3) energy requirements, (4) the amount of reductions, and (5) advancement of technology. To be consistent with this statutory construct, the EPA proposes that in determining a less stringent BSER for a designated facility, a state must also consider all these factors in applying RULOF for that source. Specifically, the plan submission must identify all control technologies available for the source and evaluate the BSER factors for each technology, using the same metrics and evaluating them in the same manner as the EPA did in developing the EG using the five criteria noted above.[267]

We are further proposing that the standard must be in the same form (*e.g.,* numerical rate-based emission standard) as required by the EG OOOOc presumptive standard. The EPA notes there may be cases where a state determines that a designated facility cannot reasonably implement the BSER but can instead reasonably implement another control measure to achieve the same level of stringency required by an EG. In such cases, the standard of performance that reflects the designated facility-specific BSER would be the same level of stringency as the degree of emission limitation achievable through application of the EPA's BSER.

The EPA solicits comment on these proposed requirements for the calculation and form of the less stringent standard that accounts for remaining useful life and other factors. The EPA believes that the five identified BSER factors generally address all relevant information that states would reasonably consider in evaluating the emission reductions reasonably achievable for a designated facility. Moreover, the EPA considers that that these factors provide states with the discretion to weigh these factors in determining the BSER and establishing a reasonable standard of performance for the source. However, the EPA solicits comments on whether there are additional factors, not already accounted for in the BSER analysis, that the EPA should permit states to consider in determining the less stringent standard for an individual source. The EPA also solicits comments on whether we should consider these factors to be part of a presumptively approvable framework for applying a less stringent standard of performance, rather than requirements, and, if so, what different approaches states might use to evaluate and identify less stringent standards that the EPA should consider to be satisfactory in evaluating state plans that apply RULOF.

The EPA also notes that CAA section 111(d) requires that state plans include measures that provide for the implementation and enforcement of a standard of performance. This requirement therefore applies to any standard of performance established by a state that accounts for RULOF. Such measures include monitoring, reporting, and recordkeeping requirements, as required by 40 CFR 60.25a, as well as any additional measures specified under EG OOOOc. In particular, any standard of performance that accounts for RULOF is also subject to the requirement under subpart Ba that the state plan submission include a demonstration that each standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable. 40 CFR 60.27a(g)(3)(vi).

e. Contingency Requirements

The EPA recognizes that a source's operations may change over time in ways that cannot always be anticipated or foreseen by the EPA, state, or designated facility. This is particularly true where a state seeks to rely on a designated facility's operational conditions, such as the source's remaining useful life or restricted capacity, as a basis for setting a less stringent standard. If the designated facility subsequently changes its operating conditions after the state applies a less stringent standard of performance, there is potential for the standard to not match what is reasonably achievable by a designated facility, resulting in forgone emission reductions and undermining the level of stringency set by EG OOOOc. For example, a state may seek to invoke RULOF for a designated facility located at a well site (*e.g.,* storage vessel) during a time when oil prices are low. The market demand may prompt the owner or operator to shut the well site which may not have been anticipated by the BSER. The well site may be shut in for the duration of the compliance period required by an EG. Under this scenario, the state may be able to demonstrate that it is not reasonably cost effective for the designated facility to implement the BSER in order to achieve the presumptive level of stringency, and the state could set a less stringent standard of performance for this storage vessel designated facility. However, because market conditions are not a physical constraint on the designated facilities operations, it is possible that oil prices can increase in the future therefore causing the production demand to increase without any other legal constraint.

The implementing regulations do not currently address this potential scenario. To address this issue, the EPA is proposing for purposes of EG OOOOc to add a contingency requirement to the RULOF provision that would require a state to include in its state plan a condition making a source's operating

[267] To the extent that a state seeks to apply RULOF to a class of facilities that the state can demonstrate are similarly situated in all meaningful ways, the EPA proposes to permit the state to conduct an aggregate analysis of these factors for the entire class.

condition, such as remaining useful life or restricted capacity, enforceable whenever the state seeks to rely on that operating condition as the basis for a less stringent standard. This requirement would not extend to instances where a state applies a less stringent standard on the basis of an unalterable condition that is not within the designated source's control, such as technical infeasibility, space limitations, water access, or subsurface reservoir and geological conditions. Rather, this requirement addresses operating conditions such as operation times, operational frequency, process temperature and/or pressure, flow rate, fuel parameters, and other conditions that are subject to the discretion and control of the designated facility.

As previously discussed, the state plan submission must also include measures for the implementation and enforcement of a standard that accounts for RULOF. For standards that are based on operating conditions that a facility has discretion over and can control, the operating condition and any other measure that provides for the implementation and enforcement of the less stringent standard must be included in the plan submission and as a component of the standard of performance. For example, if a state applies a less stringent standard for a storage vessel designated facility on the basis that the storage vessel has less throughput than maximum capacity of the storage vessel (*e.g.,* due to the current well production, or a state permit limit), the plan submission must include an enforceable requirement for the source to operate at or below that capacity factor, and include monitoring, reporting, and recordkeeping requirements that will allow the state, the EPA, and the public to ensure that the source is in fact operating at that lower capacity.

The EPA notes there may be circumstances under which a designated facility's operating conditions change permanently so that there may be a potential violation of the contingency requirements approved as federally enforceable components of the state plan. For example, a storage vessel designated facility that was previously running at lower throughput now plans to run at a higher throughput full time, which conflicts with the federally enforceable state plan requirement that the facility operate at the lower throughput. To address this concern, a state may submit a plan revision to reflect the change in operating conditions. Such a plan revision must include a new standard of performance that accounts for the change in operating conditions. The plan revision would need to include a standard of performance that reflects the level of stringency required by EG OOOOc and meet all applicable requirements, or if a less stringent standard is still warranted for other reasons, the plan revision would need to meet all of the applicable requirements for considering RULOF.

The EPA requests comment on the proposed contingency requirements to address the concern that a designated facility's operations may change over time in ways that do not match the original rationale for a less stringent standard.

f. Requirements Specific to Remaining Useful Life

Remaining useful life is the one ''factor'' that CAA section 111(d) explicitly requires that the EPA permit states to consider in applying a standard of performance. The current RULOF provision generally allows for a state to account for remaining useful life to set a less stringent standard. However, the provision does not provide guidance or parameters on when and how a state may do so. Consistent with the principles described previously in this section, the EPA is proposing certain requirements for when a state seeks to apply a less stringent standard on grounds that a designated facility will retire in the near future.

The EPA is proposing to require that in order to account for remaining useful life in setting a less stringent standard for a particular designated facility, the state plan must identify the source's retirement date and substantiate why this retirement date qualifies for the imposition of a less stringent standard. The state plan must include a demonstration of why the source's remaining useful life based on its retirement date reasonably warrants a less stringent standard and does not undermine the control objectives of the EG and CAA section 111(d) itself.

This demonstration may take into account considerations in relation to the remaining useful life such as the time needed to purchase and install equipment required to comply, the time needed to develop a compliance plan and secure the services of specialized contractors to perform services required for compliance, the expected window of time needed to obtain approvals of outside agencies, the time needed to conduct any required community outreach or public hearings, as well as other potential factors.

However, the EPA is proposing that one consideration must be addressed in every case to substantiate that the remaining useful life qualifies the imposition of a less stringent standard. That is, the state must demonstrate that the cost of control is unreasonable in relation to the retirement date.

When the EPA determines a BSER, it considers cost and, in many instances, the EPA specifically considers annualized costs associated with payment of the total capital investment of the technology associated with the BSER. In the estimation of this annualized cost, the EPA assumes an interest rate and a capital recovery period, sometimes referred to as the payback period. For example, in the estimation of the annual costs for the installation of an instrument air system to power pneumatic controllers with compressed air a medium-sized transmission and storage site, the EPA estimates that the total capital investment (equipment and installation) of the system would be $76,481. For the BSER analysis, the EPA assumed an interest rate of seven percent and a capital recovery period of 15 years. This means that the annual cost of recovering the initial capital investment including interest, was $8,397 per year for 15 years. The total annual cost includes this capital recovery cost plus the additional operation and maintenance cost of the equipment (additional beyond what would be required for a natural gas-driven controller system). For this example, the additional operation and maintenance cost was estimated to be $2,816 per year, resulting in a total annual cost of $11,213 and a cost effectiveness of $1,250 per ton of methane removed, which is a value within the range considered reasonable by the EPA.

Therefore, for this example, the cost effectiveness is reasonable considering a capital recovery period, or payback period, of 15 years. If the remaining useful life was less than 15 years, the result could be a cost effectiveness that is outside of the range considered reasonable by the EPA. For example, consider a remaining useful life of six years. The resulting capital recovery cost would be $26,742 per year and total annual cost would be $29,196. This would yield a cost effectiveness of $1,834 per ton of methane removed, which would still be in the range considered reasonable by the EPA. Therefore, the state would not be able to claim that the costs were unreasonable for a remaining useful life of six years. However, if the remaining useful life were only two years, the capital recovery cost would be $70,502 per year and the total annual cost would be $72,956. The cost effectiveness of this would be almost $4,600 per ton of methane removed, which is outside of the range considered reasonable by the EPA. In this situation, this could potentially be used as part of a demonstration that may qualify the remaining useful life for the imposition of a less stringent standard.

Note that this specific example is only for illustrative purposes. Specifically, for pneumatic controller designated facilities, there are compliance options (*e.g.,* electric controllers) that are considerably less expensive than the installation of an instrument air system. A state would have to demonstrate unreasonable cost of control for each of the identified compliance options, not just one.

The EPA proposes that the only cost factor that should be considered in a remaining useful life determination of cost unreasonableness is whether there is a significant capital investment required to design, purchase, and install equipment. A BSER based on compliance measures that do not require such upfront capital expenditures would have been demonstrated to have reasonable costs in the EPA's analysis for the presumptive standards. This would largely be the case if the affected facility operates for two years or 50 years. Therefore, the EPA does not believe that all types of designated facilities should be eligible for a determination of unreasonable costs associated with remaining useful life. Accordingly, the proposed rule would only allow that cost unreasonableness be considered in a state's demonstration that a source's remaining useful life based on its retirement date reasonably warrants a less stringent standard for the following types of designated facilities: oil wells with associated gas, storage vessels, pneumatic controllers, and pneumatic pumps. A cost unreasonableness determination would not be allowed for any other designated facility types. Note that this would not necessarily prohibit a state from making a demonstration for these other types of designated facilities, as some of the other factors mentioned above (*e.g.,* time needed to develop a compliance plan and secure the services of specialized contractors to perform services required for compliance) could be relevant for such facilities. However, a state could not rely on unreasonable cost in determining that remaining useful life justifies a less stringent standard.

The EPA recognizes that, even with the criteria outlined above, the result could be that different states could make demonstrations that result in different remaining useful life periods for the same types of designated facilities. In order to avoid this potential inequity, the EPA is requesting comment on whether EG OOOOc should include a single ''outermost retirement date'' that would define the maximum length of time that would qualify for a designated facility to operate at a less stringent standard based on remaining useful life.

As previously discussed, the EPA is proposing to require that when an operational condition is used as the basis for applying a less stringent standard, the state plan must include that condition as a federally enforceable requirement. Accordingly, if a state applies a less stringent standard by accounting for remaining useful life, the EPA is proposing to require that the state plan must include the retirement date for the designated facility as an enforceable commitment and include measures that provide for the implementation and enforcement of such commitment. For example, the state could adopt a regulation or enter into an agreed order requiring the designated facility to shut down by a certain date, and that regulation or agreed order should then be incorporated into the state plan. The state could also choose to incorporate the shutdown date into a permit, such as a preconstruction permit, and incorporate that permit into the state plan.

The EPA is further proposing to require that the state plan impose a standard that applies to a designated facility until its retirement. This standard must reflect a reasonably achievable source specific BSER and be calculated as described in section IV of this preamble and section XII of the November 2021 proposal and supported by the demonstration described in 2021 TSD [268] and the Supplemental TSD [269] for this action. The EPA recognizes that, in some instances, a designated facility may intend to retire imminently after the promulgation of an EG, and in such cases it may not be reasonable to require any controls based on the source's exceptionally short remaining useful life. In the case of an imminently retiring source, the EPA is proposing that the state apply a standard no less stringent than one that reflects the designated facility's business as usual. This requirement equitably accommodates practical considerations without impermissibly exacerbating the impacts of the pollutant regulated under CAA section 111(d). The EPA generally expects that an ''imminent'' retirement is one that is about to happen in the near term, *e.g.,* within six months.

The EPA solicits comment on the proposed requirements specific to the consideration of remaining useful life as described in this section.

g. The EPA's Standard of Review of State Plans Invoking RULOF

Under CAA section 111(d)(2), the EPA has the obligation to determine whether a state plan submission is ''satisfactory.'' This obligation extends to all aspects of a state plan, including the application of a less stringent standard of performance that accounts for RULOF. The proposed RULOF provision in EG OOOOc are intended to provide parameters not only for the development of CAA section 111(d) state plans, but for the EPA to evaluate the approvability of such plans. The EPA is proposing the following requirements to further bolster the RULOF provision and to facilitate the EPA's review of a state plan to determine whether the plan implementing the RULOF provision is ''satisfactory.'' As an initial matter, the EPA proposes to explicitly require that the state must carry the burden of making the demonstrations required under the RULOF provision. States carry the primary responsibility to develop plans that meet the requirements of CAA section 111(d) and therefore have the obligation to justify any accounting for RULOF that they invoke in support of standards less stringent than those provided by EG OOOOc. While the EPA has discretion to supplement a state's demonstration, the EPA may also find that a state plan's failure to include a sufficient RULOF demonstration is a basis for concluding the plan is not ''satisfactory'' and therefore disapprove the plan.

The EPA is further proposing that for the required demonstrations, the state must use information that is applicable to and appropriate for the specific designated facility, and the state must show how information is applicable and appropriate. As RULOF is a source-specific determination, it is appropriate to require that the information used to justify a less stringent standard for a particular designated facility be applicable to and appropriate for that source. The EPA anticipates that in most circumstances, site-specific information will be the most applicable and appropriate to use for these demonstrations and proposes to require site-specific information where available. In some instances, site-specific information may not be available, and a state may instead be able to use general information about the Crude Oil and Natural Gas source

[268] Document ID No. EPA–HQ–OAR–2021–0317–0166.

[269] Located at Docket ID No. EPA–HQ–OAR–2021–0317.

category to evaluate a particular designated facility. In such cases, the state plan submission must provide both the general information and a clear assessment of how the information is applicable to and appropriate for the designated facility. The use of general information must also be consistent with and supportive of the overall assessment and conclusions regarding consideration of RULOF for the specific designated facility.

Finally, the EPA proposes to require that the information used for a state's demonstrations under the new RULOF provisions must come from reliable and adequately documented sources, which presumptively include the following: EPA sources and publications, permits, environmental consultants, control technology vendors, and inspection reports. Requiring the use of such sources will help ensure that an accounting of RULOF is premised on legitimate, verifiable, and transparent information. The EPA solicits comment on the proposed list of information sources and whether other sources should be considered as reliable and adequately documented sources of information for purposes of the RULOF demonstration, including but not limited to reliable and adequately documented sources of cost information. [270]

These requirements will aid both the EPA in evaluating whether RULOF has been appropriately accounted for, and the public in commenting on the EPA's proposed action on a state plan that includes a less stringent standard on the basis of RULOF. The EPA solicits comment on the proposed requirements described in this section regarding the EPA's standard of review for state plans that invoke consideration of RULOF.

h. Consideration of Impacted Communities

CAA section 111(d) does not specify what are the ''other factors'' that the EPA's regulations should permit a state to consider in applying a standard of performance. The EPA interprets this as providing discretion for the EPA to identify the appropriate factors and conditions under which the circumstance may be reasonably invoked in establishing a standard less stringent than the EG. Additionally, CAA section 111(d)(2)'s requirement that the EPA determine whether a state plan is ''satisfactory'' applies to such plan's consideration of RULOF in applying a standard of performance to a particular facility. Accordingly, the EPA must determine whether a plan's consideration of RULOF is consistent with section 111(d)'s overall health and welfare objectives. While the consideration of RULOF can be warranted to apply a less stringent standard of performance to a particular facility, such standards have the potential to result in disparate health and environmental impacts to communities most affected by and vulnerable to impacts from the designated facilities being addressed by the state plan. Those communities could be put in the position of bearing the brunt of the greater health and environmental impacts resulting from that source implementing less stringent emission controls than would otherwise have been required pursuant to the EG. The EPA finds that a lack of consideration to such potential outcomes would be antithetical to the public health and welfare goals of CAA section 111(d) and the CAA generally.

In order to address the potential exacerbation of health and environmental impacts to vulnerable communities as a result of applying a less stringent standard, the EPA is proposing in EG OOOOc to require states to consider such impacts when applying the RULOF provision to establish those standards. The EPA is proposing to require that, to the extent a designated facility would qualify for a less stringent standard through consideration of RULOF, the state, in calculating such standard, must consider the potential health and environmental impacts on communities most affected by and vulnerable to the impacts from the designated facility considered in a state plan for RULOF provisions. These communities will be identified by the state as pertinent stakeholders under the proposed meaningful engagement requirements described in section V.B.6 of this preamble.[271]

The EPA proposes to require that state plan submissions seeking to invoke RULOF for a source must identify where and how a less stringent standard impacts these communities. In evaluating a RULOF option for a facility, states should describe the health and environmental impacts anticipated from the application of RULOF for such communities, along with any feedback the state received during meaningful engagement regarding its draft state plan submission, including on any standards of performance that consider RULOF. Additionally, to the extent there is a range of options for reasonably controlling a source based on RULOF, the EPA is proposing that in determining the appropriate standard of performance, states should consider the health and environmental benefits to the communities most affected by and vulnerable to the impacts from the designated facility considered in a state plan for RULOF provisions, and also provide in the state plan submission a summary of the results that depicts the impacts to those communities. This requirement to consider the health and environmental impacts in any standard of performance taking into account RULOF is consistent with the definition of ''standard of performance'' in CAA section 111(a)(1). This definition requires the EPA to take into account health and environmental impacts in determining the BSER. As described in this section, if a designated facility qualifies for a less stringent standard based on RULOF, the EPA is proposing the state plan must identify a source-specific BSER based on the same factors and metrics the EPA considered in determining the BSER in the EG. Therefore, state plans must consider health and environmental impacts in determining a source-specific BSER informing a RULOF standard, just as the EPA is statutorily required to take into account these factors in making its BSER determination. See section IV.D.1.b.III for an example of the environmental impacts assessed for the EPA's proposed BSER determination for pneumatic controllers.

As an example, the state plan submission could include a comparative analysis assessing potential controls on a designated facility and the corresponding potential benefits to the identified communities in controlling the designated facility. If the comparative analysis shows that a designated facility could be controlled at a certain cost threshold higher than required under the EPA's proposed revisions to the RULOF provision, and such control benefits the communities that would otherwise be adversely impacted by a less stringent standard, the state in accounting for RULOF could choose to use that cost threshold to apply a standard of performance.[272]

[270] The EPA acknowledges there may be reliable and adequately documented sources of information other than those described in this section. The EPA encourages states to consult with their Regional Offices if there are questions about whether a particular source of information would meet the applicable requirements.

[271] Pursuant to the proposed meaningful engagement requirements that states must complete prior to the submittal of their state plans, states must identify pertinent stakeholders and meaningfully engage with such pertinent stakeholders, including communities most affected by and vulnerable to the impacts of the plan.

[272] As previously described, CAA section 111(d) gives states the discretion to consider RULOF for a particular source and are not required to do so.

Given that states have the discretion rather than mandate to consider RULOF in applying a standard of performance under CAA section 111(d), it is reasonable for states to consider the potential impacts to communities most affected by and vulnerable to the impacts from a particular designated facility in calculating the level of stringency for such standard.

Additionally, under CAA section 111(d)(2)(B), the EPA has the authority to prescribe a Federal plan promulgating a standard of performance for designated facilities located in a state that fails to submit a satisfactory plan. Consistent with the statute's mandate for the EPA's regulations under CAA section 111(d) to permit states to account for RULOF, this provision further directs that the EPA ''shall'' take into account RULOF in promulgating standards of performance for the source category under the Federal plan. Therefore, because the statute uses the same ''other factors'' phrasing in both CAA sections 111(d)(1) governing state plans and 111(d)(2) governing Federal plans, the EPA proposes in EG OOOOc to require that impacts to communities most affected by and vulnerable to the impacts from designated facilities be considered in both the state and Federal plan contexts when accounting for RULOF.

The EPA solicits comment on the proposed requirements described in this section for consideration of vulnerable communities in the context of RULOF.

i. Authority To Apply More Stringent Standards as Part of the State Plan

In the November 2021 proposal, the EPA proposed that states are authorized to include in their state plans, and the EPA is authorized to approve, requirements that are more stringent than the EG under the authority of CAA section 116, as interpreted by the Court in *Union Electric* v. *EPA,* 27 U.S. 246, (1976). 86 FR 63251. The EPA is now proposing that under CAA section 111(d), consistent with the authority conferred by CAA section 116, states may consider RULOF to include more stringent standards of performance in their state plans.

The current RULOF provision in subpart Ba under 40 CFR 60.24a(e) governs instances where states seek to apply a less stringent standard of performance to a particular designated facility. In promulgating this provision, the EPA received comments contending that if states may consider factors that justify less stringent standards, they must also be permitted to consider factors that would justify greater stringency than required by an EG, such as more expeditious compliance obligations or the retirement of a source. EPA's Responses to Public Comments on the EPA's Proposed Revisions to Emission Guideline Implementing Regulations at 56 (Docket ID No. EPA–HQ–OAR–2017–0355–26740) (July 8, 2019). In response to these comments, the EPA explained that it interpreted the statutory RULOF provision as intended to authorize only standards of performance that are less stringent than the presumptive level of stringency required by a particular EG. *Id.* at 57. The EPA has reevaluated its prior interpretation and is now proposing for purposes of EG OOOOc to interpret that the statute authorizes the EPA to permit states to consider other factors that justify application of a more stringent standard to a particular source than required by an EG. See *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502 (2009). The EPA's rationale for its revised interpretation and proposal is as follows.

As described previously, while standards of performance must generally reflect the presumptive level of stringency identified in the EG, CAA section 111(d) also requires the EPA to permit states to ''take into consideration, among other factors, the remaining useful life'' in applying a standard of performance to a particular designated facility. Aside from the explicit reference to remaining useful life, the statute is silent as to what the ''other factors'' are that states may consider in applying a standard of performance. It also silent as to whether the ''standard of performance'' to be ''appl[ied]'' to a ''particular source'' must be a weaker or stronger standard—the only inference that can be drawn from the statutory language is that RULOF may be used to apply a *different* standard. Therefore, the EPA may reasonably interpret this ambiguity both as to what the ''other factors'' are that states may use to apply a standard of performance to a particular source, and how such consideration may affect the stringency of such standard. Accordingly, the EPA reasonably interprets this phrase as authorizing states to consider other factors in exercising their discretion to apply a more stringent standard to particular a source. This is a reasonable interpretation of the statute because if Congress intended the RULOF provision to be used only to allow states to apply less stringent standards, it would have clearly specified that its intent or enumerated ''other factors'' that are appropriate for relaxing the stringency of a standard. The statute's explicit reference to remaining useful life shows that if there were factors that Congress specifically wanted the EPA to allow or disallow states to consider, it knew how to expressly make its intent clear in the RULOF provision.

In addition to finding that the statute does not preclude the EPA's reasonable interpretation of the statutory RULOF provision as described above, the EPA has reevaluated the bases for its prior interpretation that states may only consider RULOF to apply a less stringent standard and determined those bases were flawed. In making its prior interpretation, the EPA noted that the new regulatory RULOF provision under subpart Ba at 40 CFR 60.24a(e) was substantively similar to the variance provision under subpart B, which authorizes the use of other factors that ''make application of a less stringent standard or final compliance time significantly more reasonable.'' 40 CFR 60.24(f)(3). The EPA reasoned that because the variance provision under subpart B is similar to and predated Congress's addition of the statutory RULOF provision to CAA section 111(d) as part of the 1977 CAA Amendments, ''Congress effectively ratified the EPA's implementing regulations' clear construct that remaining useful life and other factors are only relevant in the context of setting less stringent standards.'' EPA's Responses to Public Comments on the EPA's Proposed Revisions to Emission Guideline Implementing Regulations at 57 (Docket ID# No. EPA–HQ–OAR–2017–0355–26740) (July 8, 2019). The EPA has closely reexamined the variance provision under subpart B and the RULOF provision under CAA section 111(d) and does not find that these provisions support the proposition that Congress clearly ratified the aspect of the variance provision in subpart B allowing states to apply only less stringent standards under certain circumstances. There are notable differences between the subpart B variance provision and the CAA section 111(d) RULOF provision that indicate Congress did not intend to incorporate and ratify all aspects of the EPA's regulatory approach when amending CAA section 111(d) in 1977. Particularly, for pollutants found to cause or contribute to endangerment of public health, subpart B allows states to apply a less stringent standard under

States thus have the authority to choose to impose a more stringent standard, including the presumptive standard, than would be permissible under RULOF for other reasons, *e.g.* based on consideration of communities other than identified impacted communities.

certain circumstances unless the EPA provides otherwise in a specific EG for a particular designated facility or class of facilities. 40 CFR 60.24(c), (f). Subpart B places no similar exception for states in authorizing them to seek a variance for a standard addressing a pollutant for which the EPA has made a welfare-based, but not public health-based, endangerment finding under 111(b)(1)(A). 40 CFR 60.24(d). By contrast, the statutory RULOF provision does not make a similar distinction between public health and welfare-based pollutants, which the EPA itself acknowledged in promulgating the regulatory RULOF provision in subpart Ba. 84 FR 32570 (July 8, 2019). Therefore, the EPA cannot clearly ascertain whether the statutory RULOF provision ratified the variance provision under subpart B, given that certain key elements of the latter are not present in the former. There is nothing in CAA section 111(d) or the legislative history that suggests Congress enacted the statutory RULOF provision by ratifying certain elements of the regulatory variance provision in subpart B but not others.

Additionally, in taking its prior position that states may only consider RULOF to apply a less stringent standard, the EPA asserted that the legislative history of the 1977 CAA Amendments supported its interpretation. The EPA highlighted the following statement in the House conference report adopting the amendment to add the statutory RULOF provision: ''The section also makes clear that standards adopted for existing sources under section 111(d) of the Act are to be based on available means of emission control (not necessarily technological) and must, unless the state decides to be more stringent, take into account the remaining useful life of the existing sources.'' H.R. Conf. Rep. No. 94–1742, (Sep. 30, 1976), 1977 CAA Legis. Hist. at 88. Based on this statement, the EPA found that the caveat that states have the choice to not invoke the RULOF provision and instead ''be more stringent'' suggests that considering RULOF is only intended to allow a state to make a standard less stringent. The EPA now finds that its prior reliance on this legislative history was flawed. The cited statement only speaks to remaining useful life, which is a factor that inherently suggests a less stringent standard, but it is completely silent as to the ''other factors'' the statute references. Thus, there is no indication that Congress intended to limit the ''other factors'' that states may apply in developing their plans only to permit less stringent, and not also more stringent standards. Rather, the cited statement explicitly acknowledges that states may choose to ''be more stringent'', which supports the EPA's interpretation of the statute to permit states to consider other factors to set standards more stringent than the degree of emission limitation achievable through application of the BSER.

Interpreting the statutory RULOF provision as authorizing states to apply a more stringent standard of performance to a particular source is also consistent with the purpose and structure of CAA section 111(d). CAA section 111(d) clearly contemplates cooperative federalism, where states bear the obligation to establish standards of performance. Nothing under CAA section 111(d) suggests that the EPA has the authority to preclude states from determining that it is appropriate to regulate certain sources within their jurisdiction more strictly than otherwise required by federal requirements. To do so would be arbitrary and capricious in light of the overarching purpose of CAA section 111(d), which is to require emission reductions from existing sources for certain pollutants that endanger public health or welfare. It is inconsistent with the purpose of CAA section 111(d) and the role it confers upon states for the EPA to constrain them from further reducing emissions that harm their citizens, and the EPA does not see a reasonable basis for doing so.

Other factors states may wish to account for in applying a more stringent standard than required under an EG include, but are not limited to, early retirements, effects on local communities, and availability of control technologies that allow a source to achieve greater emission reductions. However, the EPA cannot anticipate each and every factor under which a state may seek to apply a more stringent standard. Therefore, the EPA will evaluate on a case-by-case basis the inclusion of a more stringent standard in a state plan addressing EG OOOOc. The EPA is also proposing to require that states seeking to apply a more stringent standard of performance based on other factors must adequately demonstrate that the different standard is in fact more stringent than the presumptive level of stringency. Such standard of performance must meet all applicable statutory and regulatory requirements, including that it is adequately demonstrated,[273] and the state plan must include measures that provide for the implementation and enforcement of the standard as with any standard of performance under CAA section 111(d).

For the reasons described in this section, the EPA proposes to permit states to consider factors which justify applying a standard of performance that is more stringent than required under an EG OOOOc.

Therefore, for purposes of EG OOOOc, per the authority of CAA sections 111(d) and 116, the EPA proposes to permit states to include more stringent standards of performance in their plans and that the EPA must approve and render such standards as federally enforceable, so long as the minimum requirements of the EG and subpart Ba are met.[274] The EPA solicits comment on its proposal as described in this section.

4. Providing Measures That Implement and Enforce Such Standards

As described in the November 2021 proposal, the EPA proposed to require that state plans must also include compliance schedules for the presumptive standards including where states choose to account for RULOF, methods employed to implement and enforce the presumptive standards such that the EPA can review and identify measures that assure transparent and verifiable implementation, and states must include appropriate monitoring, reporting, and recordkeeping requirements to ensure that state plans adequately provide for the implementation and enforcement of the presumptive standards.[275] The EPA is proposing to supplement the November 2021 proposal by clarifying that states maintain the same monitoring, reporting, and recordkeeping requirements, or equivalent requirements as described in EG OOOOc for presumptive standards that states adopt in their plans. The EPA further clarifies that where a state plan adopts standards of performance that

[273] The EPA is not proposing to require the state to conduct a source-specific BSER analysis for purposes of applying a more stringent standard, as the EPA proposes to require for application of a less stringent standard. So long as the standard will achieve equivalent or better emission reductions than required by EG OOOOc, the EPA believes it is appropriate to defer to the state's discretion to, *e.g.,* choose to impose more costly controls on an individual source.

[274] The EPA notes that its authority is constrained to approving measures which comport with applicable statutory requirements. For example, CAA section 111(d) only contemplates that state plans would include requirements for designated facilities regulated by a particular EG; therefore, the EPA concludes that CAA section 116 does not provide it with the authority to approve and render federally enforceable measures on entities other than those on designated facilities.

[275] 86 FR 63252 (November 15, 2021).

differ from the presumptive standards, the plan may accordingly include different monitoring, reporting, and recordkeeping requirements than those in the presumptive standards, but such requirements must be appropriate for the implementation and enforcement of the standards and must be determined to be equivalent as described in Section V.B.2. For components of a state plan that differ from any presumptively approvable aspects of the final EG, the EPA will review the approvability of such components through notice and comment rulemaking.

5. Emissions Inventories

In the November 2021 proposal the EPA discussed that the implementing regulations at 40 CFR 60.25a contain generally applicable requirements for emission inventories, source surveillance, and reports. 86 FR 63253 (November 16, 2021). 40 CFR 60.25a(a) requires that state plans shall include an inventory of all designated facilities, including emission data for the designated pollutants. This provision further requires that such data shall be summarized in the plan, and emission rates of designated pollutants from designated facilities shall be correlated with applicable standards of performance. However, due to the very large number of existing oil and natural gas sources,[276] and the frequent change of configuration and/or ownership, the EPA recognized that it may not be practical to require states to compile this information in the same way that is typically expected for other industries under other EG. Therefore, the EPA solicited comment on whether to supersede the requirements of 40 CFR 60.25a(a) for purposes of this EG.[277]

State commenters generally support superseding the implementing regulations and agree that states should be able to document impacted sources differently than other CAA section 111(d) plans.[278] While some state commenters have state inventories, others confirmed the EPA's understanding that some states do not have comprehensive tracking systems for a designated facility inventory and associated emissions.[279] Some commenters discussed that the development of such an inventory would be resource intensive with little benefit.[280] The State of Colorado referenced their 2020 leak inspection reporting program which suggests there are over 15,000 well production facilities in the state and the State of West Virginia estimates over 54,000 natural gas and over 10,000 crude oil producing wells in the state.[281] Both states recognize that each well production facility would represent a much greater number of individual designated facilities. The State of West Virginia further described the complexity of inventory development given not only the vast number of sources, but also the frequent change of configurations and ownership within the industry. These points were echoed by the State of Texas which also provided an estimate of the number of production wells in the state, however, they noted that unless a state-wide equipment inventory is conducted the number of designated facilities is unclear.[282] Multiple state commenters support the EPA allowing states to leverage existing inventories and emissions data, even if that data might not be fully aligned with the designated facilities in the EG.[283]

For purposes of this EG, the EPA does not believe that the inventory and detailed emissions data required under 40 CFR 60.25a(a) is necessary for states to develop standards of performance, and that standards of performance could be developed with a different type of emissions inventory data. For example, the emissions inventory data could be derived from the GHGRP, which collects GHG emissions and activity data annually from applicable facilities conducting petroleum and natural gas systems activities. Facilities use uniform methods prescribed by the EPA to calculate emissions for applicable source types, and the EPA conducts a multi-step verification process to ensure reported data are accurate, complete, and consistent. Reported data are made available to the public through several portals accessible via the EPA's website. The emissions and activity data reported to the GHGRP can be leveraged to develop standards of performance. While the EPA recognizes that the GHGRP includes a reporting threshold and that GHGRP facility definitions and emission factors might not be fully aligned with the designated facilities in the EG, the GHGRP data represent the same general type of inventory information as the inventory and detailed emissions data required under 40 CFR 60.25a(a). In addition, the EPA does not think it reasonable to burden states to derive information from GHGRP, which the EPA already has, only to resubmit it to the Agency. The EPA notes that emissions inventory data used to develop standards of performance could also be derived from other available existing inventory information available to the state. Therefore, in order to avoid the potential burden that could be imposed by applying 40 CFR 60.25a(a) as written to this EG, and potential burden and duplicative information collection imposed by requiring states to use other inventories such as GHGRP, the EPA proposes to supersede the requirements of 40 CFR 60.25a(a) for purposes of this EG, so that state plans are not required to include an inventory and emissions data as described under this provision.

6. Meaningful Engagement

In the November 2021 proposal, the EPA proposed and solicited comment on requiring states to perform early outreach and meaningful engagement with overburdened and underserved communities during the development process of their state plan pursuant to EG OOOOc.[284] The fundamental purpose of CAA section 111 is to reduce emissions from certain stationary sources that cause, or significantly contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare. Therefore, a key consideration in the state's development of a state plan, in any significant plan revision,[285] and in the EPA's development of a Federal plan pursuant to an EG promulgated under CAA section 111(d) is the potential impact of the proposed plan requirements on public health and welfare. A robust and meaningful public participation process during plan development is critical to ensuring that the full range of these impacts are understood and considered. The EPA received numerous comments from states supporting the proposed

[276] In the U.S. the EPA has identified over 15,000 oil and gas owners and operators, around 1 million producing onshore oil and gas wells, about 5,000 gathering and boosting facilities, over 650 natural gas processing facilities, and about 1,400 transmission compression facilities.

[277] The EPA may supersede any requirement in its implementing regulations for CAA section 111(d) if done so explicitly in the EG. See 40 CFR 60.20a(a)(1).

[278] The EPA received several comments on this topic. A sampling of these comments is cited in footnotes in this section. See Document ID Nos. EPA–HQ–OAR–2021–0317–0769, EPA–HQ–OAR–2021–0317–0775.

[279] See Document ID Nos. EPA–HQ–OAR–2021–0317–0832–A2, EPA–HQ–OAR–2021–0317–0722.

[280] See Document ID Nos. EPA–HQ–OAR–2021–0317–0200.

[281] See Document ID Nos. EPA–HQ–OAR–2021–0317–0775, EPA–HQ–OAR–2021–0317–0424.

[282] See Document ID Nos. EPA–HQ–OAR–2021–0317–0419.

[283] See Document ID Nos. EPA–HQ–OAR–2021–0317–1267.

[284] See 86 FR 63254 (November 15, 2021).

[285] Significant state plan revision includes, but is not limited to, any revision to standards of performance or to measures that provide for the implementation or enforcement of such standards.

requirements for meaningful engagement, providing suggestions based on their own experience and initiatives, while requesting that the EPA provide specificity around meaningful engagement and examples of satisfactory engagement. The EPA also hosted two discussions with representatives of state and local air agencies to hear more about their perspectives on meaningful engagement. The Agency held a similar meeting with communities, tribes, and small businesses to hear their views on meaningful engagement.

Many stakeholders support robust public engagement, especially with communities most affected by and vulnerable to the impacts of the state plan, and some highlight how this type of public engagement aligns with their commitment to EJ.[286] State commenters also encouraged the EPA to allow for flexibility to craft plans to the unique economic and demographic features of each state.[287] Some states and industry commenters question the EPA's authority to require states to conduct meaningful engagement and seek guidance on alternative procedures for meaningful engagement.[288] Other state commenters indicate that states already take EJ initiatives into consideration and some say additional efforts would be redundant and share concern about adequate resources to conduct meaningful engagement.[289] State commenters generally advocate for the EPA to provide examples of the types of engagement that will be approvable and seek additional guidance. Industry commenters expressed commitment to support constructive interactions between industry, regulators, and surrounding communities and populations that may be disproportionately impacted.[290] Some industry and state commenters express concern that the meaningful engagement requirement could cause disapproval of a state plan if the EPA fails to provide a definition for meaningful engagement with clear parameters and examples of adequate engagement.[291]

State commenters offer an array of helpful suggestions based on their own experience and initiatives. New Mexico, for example, agreed with the EPA that requiring states to share information and solicit input from stakeholders at critical junctures during plan development will ensure communities have abundant opportunities to participate in the plan development process.[292] New Mexico further agreed with the EPA's proposal to give the reasonable notice requirement additional and separate meaning from ''public hearing'' to ensure the public has reasonable notice of relevant information, as well as the opportunity to participate in the state plan development.

New Mexico discusses that in addition to using traditional communication technologies, even with potential barriers involving accessibility of technologies (*e.g.,* video conferencing, social media, and smart phone applications), these new technologies should also be utilized during the meaningful engagement process and they specifically ask the EPA to permit both new and traditional communication technologies to qualify as a means to conduct meaningful public engagement. New Mexico also suggests that states, local governments, community organizations, and other stakeholders may find it helpful to create organized groups that can help address interstate air quality issues. For example, they participate in the Four Corners Air Quality Group, which could serve as a model for such coordination. New Mexico, along with the Navajo Nation, Colorado, Arizona, and Utah meet regularly to address common air quality issues in the region. The Four Corners Air Quality Group also includes a variety of different stakeholders including community members and organizations and industry leaders. The goals and functions of any cross-border groups can, and should, be crafted to the unique needs of the area(s) in which they serve.

States and Cities provided other examples of strategies for states to consider.[293] They first suggest targeting special notice, by mail, of public participation opportunities to residents and schools within a certain radius from regulated oil and natural gas facilities. Their second suggestion includes hosting a series of public meetings or workshops to provide background on the purpose of the state plans, the process for developing the plans, and the public comment and hearing process. Third, they suggest assuring that those public meetings, workshops, and hearings are held at times that are convenient for members of the affected community, that translation services are available at such events, and that there are options for participating via phone or videoconference. Fourth, they recommend ensuring that any public meeting, workshop, hearing, or other format for gathering input are safe spaces and that participation does not endanger community members because of immigration or employment status. Fifth, they suggest providing information on a public website and in hardcopy at an accessible location within the community, such as a public library or school. Lastly, they agree that the state plan submission would need to describe and report on the engagement conducted which would be evaluated as part of the state plan completeness determination. Commenters also seek additional guidance on how states could go about making public meetings or workshops safe spaces for undocumented members of overburdened or underserved communities. Similarly, commenters ask if the EPA could specify that information about the rulemaking to be shared at a public meeting or workshop must be translated in communities with linguistic barriers by the EPA's duties under Title VI the Civil Rights Act.

The EPA previously proposed in EG OOOOc to include certain meaningful engagement in addition to the requirements for notice and public hearing. The notice and public hearing requirements in 40 CFR 60.23a(c)–(f) require the states to conduct one or more public hearings prior to the adoption of any plan. The states are to provide notification to the public by prominent advertisement to the public of the date, time, and place of the public hearing, 30 days prior to the date of such hearing, and the advertisement requirement may be satisfied through the internet. *Id.* at (d).

The EPA recognizes that a fundamental purpose of the Act's notice and public hearing requirements is for all affected members of the public, and not just a particular subset, to participate in pollution control planning processes that impact their health and

[286] The EPA received several comments on this topic. A sampling of these comments are cited in footnotes in this section. See Document ID Nos. EPA–HQ–OAR–2021–0317–0581, EPA–HQ–OAR–2021–0317–0808–A1, EPA–HQ–OAR–2021–0317–0921, EPA–HQ–OAR–2021–0317–0938, EPA–HQ–OAR–2021–0317–0814, EPA–HQ–OAR–2021–0317–0832–A2, EPA–HQ–OAR–2021–0317–0727, EPA–HQ–OAR–2021–0317–0775, and EPA–HQ–OAR–2021–0317–1267.

[287] See Document ID Nos. EPA–HQ–OAR–2021–0317–0832–A2 and EPA–HQ–OAR–2021–0317–0581.

[288] See Document ID Nos. EPA–HQ–OAR–2021–0317–0727, EPA–HQ–OAR–2021–0317–0921, EPA–HQ–OAR–2021–0317–0938, EPA–HQ–OAR–2021–0317–0921, EPA–HQ–OAR–2021–0317–0763, EPA–HQ–OAR–2021–0317–0722.

[289] See Document ID Nos. EPA–HQ–OAR–2021–0317–0775 and EPA–HQ–OAR–2021–0317–0727.

[290] See Document ID Nos. EPA–HQ–OAR–2021–0317–0808–A1, EPA–HQ–OAR–2021–0317–0445, EPA–HQ–OAR–2021–0317–0819, and EPA–HQ–OAR–2021–0317–0456.

[291] See Document ID Nos. EPA–HQ–OAR–2021–0317–0921 and EPA–HQ–OAR–2021–0317–0938.

[292] See Document ID Nos. EPA–HQ–OAR–2021–0317–0832–A2.

[293] See Document ID Nos. EPA–HQ–OAR–2021–0317–1267.

welfare.[294] Accordingly, in order for there to be a meaningful opportunity for the public to participate in hearings on CAA section 111(d) state plans, the notice of such hearings must be reasonably adequate in its ability to reach affected members of the public. Many states provide for notification of public engagement through the internet, however there cannot be a presumption that such notification is adequate in reaching all those who are impacted by a CAA section 111(d) state plan and would benefit the most from participating in a public hearing. For example, data shows that as many as 30 million Americans do not have access to broadband infrastructure that delivers even minimally sufficient speeds, and that 25 percent of adults ages 65 and older report never going online.[295] Examples of prominent advertisement for a public hearing, in addition to through the internet, may include notice through newspapers, libraries, schools, hospitals, travel centers, community centers, places of worship, gas stations, convenience stores, casinos, smoke shops, Tribal Assistance for Needy Families offices, Indian Health Services, clinics, and/or other community health and social services as appropriate for the emission guideline addressed.

Given the public health and welfare objectives of CAA section 111(d) in regulating specific existing sources, the EPA believes it is reasonable to require meaningful engagement as part of the state plan development public participation process in order to further these objectives. Additionally, CAA section 301(a)(1) provides that the EPA is authorized to prescribe such regulations ''as are necessary to carry out [its] functions under [the CAA].'' The proposed meaningful engagement requirements would effectuate the EPA's function under CAA section 111(d) in prescribing a process under which states submit plans to implement the statutory directives of this section. Therefore, the EPA is proposing additional meaningful engagement requirements to ensure that pertinent stakeholders have reasonable notice of relevant information and the opportunity to participate in the state plan development throughout the process. The EPA intends to propose similar meaningful engagement provisions to this provision under the implementing regulations in a separate upcoming rulemaking that would apply generally to new EG promulgated under CAA section 111(d). While inviting comments on the application of these proposed revisions in the context of the oil and gas sector in this rulemaking, the EPA also encourages the public to provide comments on these proposed revisions more generally in that upcoming rulemaking process to amend the implementing regulations. The EPA intends to finalize that rulemaking before finalizing this oil and gas rulemaking.

Consistent with its intended addition to the implementing regulations, in this supplemental proposal, the EPA is proposing regulatory text for EG OOOOc in 40 CFR 60.5365c regarding the proposed meaningful engagement requirements that states must complete prior to the submittal of their state plans. In particular, the EPA is proposing to define meaningful engagement as ''. . . timely engagement with pertinent stakeholder representation in the plan development or plan revision process. Such engagement must not be disproportionate nor favor certain stakeholders. It must include the development of public participation strategies to overcome linguistic, cultural, institutional, geographic, and other barriers to participation to assure pertinent stakeholder representation, recognizing that diverse constituencies may be present within any particular stakeholder community. It must include early outreach, sharing information, and soliciting input on the State plan.'' The EPA is also proposing to define that pertinent stakeholders ''. . .include, but are not limited to, industry, small businesses, and communities most affected by and/or vulnerable to the impacts of the plan or plan revision.'' Increased vulnerability of communities may be attributable, among other reasons, to both an accumulation of negative and lack of positive environmental, health, economic, or social conditions within these populations or communities. Examples of such communities have historically included, but are not limited to, communities of color (often referred to as ''minority'' communities), low-income communities, tribal and indigenous populations, and communities in the United States that potentially experience disproportionate health or environmental harms and risks as a result of greater vulnerability to environmental hazards. Tribal communities or communities in neighboring states may also be impacted by a state plan and, if so, should be identified as pertinent stakeholders. In addition, to the extent a designated facility would qualify for a less stringent standard through consideration of RULOF as described in section V.B.3.h of this preamble, the state, must identify and engage with the communities most affected by and vulnerable to the health and environmental impacts from the designated facility considered in a state plan for RULOF provisions. The EPA expects that the inclusion of the definitions of meaningful engagement and pertinent stakeholders in EG OOOOc will provide the states specificity around the meaningful engagement requirements while allowing for flexibility in the implementation of such requirements.

In the November 2021 proposal, the EPA proposed to include a requirement for a demonstration of meaningful engagement as part of the completeness evaluation of a state plan submittal. The EPA is proposing regulatory text associated to the proposed meaningful engagement demonstration states are to include in their plans as part of the completeness criteria. The EPA is proposing that a state would be required to provide, in their plan submittal, a list of the pertinent stakeholders and a summary of engagement conducted and of the stakeholder input provided. The EPA would evaluate the states' demonstrations regarding meaningful engagement as part of its completeness evaluation of a state plan submittal. If a state plan submission does not include the required elements for public participation, including requirements for meaningful engagement, this may be grounds for the EPA to find the submission incomplete or to disapprove the plan. The EPA is soliciting comment on the proposed definitions of meaningful engagement and pertinent stakeholders as well as the inclusion of meaningful engagement requirements in completeness criteria for state plan submission. The EPA also solicits comments on examples or models of meaningful engagement by states, including best practices and challenges.

During the state plan process, the EPA expects states to identify the pertinent stakeholders. As part of efforts to ensure

[294] Consistent with this principle of providing reasonable notice under the CAA, under programs other than CAA section 111(d), the EPA similarly requires states to provide specific notice to an area affected by a particular proposed action. *See e.g.,* 40 CFR 51.161(b)(1) requiring specific notice for an area affected by a state or local agency's analysis of the effect on air quality in the context of the New Source Review program; 40 CFR 51.102(d)(2), (4), and (5) requiring specific notice for an area affected by a CAA section 110 SIP submission.

[295] FACT SHEET: Biden-Harris Administration Mobilizes Resources to Connect Tribal Nations to Reliable, High-Speed internet (Dec. 22, 2021). *https://www.whitehouse.gov/briefing-room/statements-releases/2021/12/22/fact-sheet-biden-harris-administration-mobilizes-resources-to-connect-tribal-nations-to-reliable-high-speed-internet/;* 7% of Americans don't use the internet. Who are they? Pew Research Center (Apr. 2, 2021), *https://www.pewresearch.org/fact-tank/2021/04/02/7-of-americans-dont-use-the-internet-who-are-they/.*

meaningful engagement, states will share information and solicit input on plan development and on any accompanying assessments. This engagement will help ensure that plans achieve the appropriate level of emission reductions, that communities most affected by and vulnerable to the health and environmental impacts from the designated facilities partake in the benefits of the state plan, and that these communities are protected from being adversely impacted by the plan. In addition, the EPA recognizes that emissions from designated facilities could cross state and/or Tribal borders, and therefore may affect communities in neighboring states or Tribal lands. The EPA expects that the discussion in section VI of the November 2021 proposal (86 FR 63139) will assist the states in the identification of pertinent stakeholders. The EPA is soliciting comment on how meaningful engagement should apply to pertinent stakeholders inside and outside of the borders of the state that is developing a state plan, for example, if a state should coordinate with the neighboring state and/or tribes for engagement or directly contact the affected communities.

The EPA further proposes to allow a state to request the approval of different state procedures for public participation. The EPA proposes to require that such alternate state procedures do not supersede the meaningful engagement requirements, so that a state would still be required to comply with the meaningful engagement requirements even if they apply for a different procedure than the other public notice and hearing requirements. The EPA is however also proposing that states may apply for, and the EPA may approve, alternate meaningful engagement procedures if, in the judgement of the Administrator, the procedures, although different from the requirements of this subpart, in fact provide for adequate notice to and meaningful engagement of the public. The EPA is soliciting comment on the distinction between request for approval of alternate state procedures to meet public notice and hearing requirements from those to meet meaningful engagement, and comment on the consideration of request for approval of alternate meaningful engagement procedures.

The EPA conducted meaningful engagement prior to the November 2021 proposal. The EPA believes this example will provide states with ideas for how they can structure their own meaningful engagement activities. States are not limited by the EPA's example, but rather the EPA's example should be viewed as a minimum of what type of engagement is considered sufficient to meet the meaningful engagement requirement for purpose of state plan submittal.

Prior to the November 2021 proposal, the EPA identified stakeholder groups likely to be interested in the proposal and engaged with them in several ways including through meetings, training webinars, and public listening sessions to share information with stakeholders about this action, on how stakeholders may comment on the proposed rule, and to hear their input about the industry and its impacts as we were developing this proposal.[296] Specifically, on May 27, 2021, the EPA held a webinar-based training designed for communities affected by this rule.[297] This training provided an overview of the Crude Oil and Natural Gas Industry and how it is regulated and offered information on how to participate in the rulemaking process. The EPA also held virtual public listening sessions June 15 through June 17, 2021, and heard various community and health related themes from speakers who participated.[298] [299]

In addition to the trainings and listening sessions, the EPA engaged with community leaders potentially impacted by this proposed action by hosting a meeting with EJ community leaders on May 14, 2021. The EPA provided the public with factual information to help them understand the issues addressed by the November 2021 proposal. We obtained input from the public, including communities, about their concerns about air pollution from the oil and gas industry, including receiving stakeholder perspectives on alternatives. The EPA considered and weighed information from communities as the agency developed the November 2021 proposal.

In addition to the engagement conducted prior to the November 2021 proposal, the EPA provided the public, including those communities disproportionately impacted by the burdens of pollution, opportunities to engage in the EPA's public comment period for this proposal, including by hosting trainings on the proposed rule and a public hearing. EPA hosted three half-day trainings November 16 through 18, 2021, to provide background information, an overview of the proposed rule, stakeholder panel discussions, and information on how to effectively engage in the regulatory process. The trainings were open to the public, with a focus on communities with EJ concerns, Tribes and small business stakeholders. The public hearing occurred on November 30 to December 2, 2021, and the EPA requested speakers discuss:

- What impacts they are experiencing (*i.e.,* health, noise, smells, economic),
- How the community would like the EPA to address their concerns,
- How the EPA is addressing those concerns in the rulemaking, and
- Any other topics, issues, concerns, etc. that the public may have regarding this proposal.

The EPA expects that the description of the meaningful engagement with pertinent stakeholders included in the preamble and in the docket of this rulemaking will serve as a guide of the meaningful engagement demonstration states are to include in their plans as part of the completeness criteria.

C. Components of State Plan Submission

While the EPA is not proposing any changes from the November 2021 proposal to this section, the EPA is proposing to add a provision for electronic submission of state plans. The provision at 40 CFR 60.23a(a)(1) currently requires state plan submissions to be made in accordance with the provision in 40 CFR 60.4. Pursuant to 40 CFR 60.4(a), all requests, reports, applications, submittals, and other communications to the Administrator pursuant to 40 CFR part 60 shall be submitted in duplicate to the appropriate Regional Office of the EPA. The provision in 40 CFR 60.4(a) then proceeds to include a list of the corresponding addresses for each Regional Office. In this supplemental proposal, the EPA is proposing to require electronic submission of state plans instead of paper copies as according to 40 CFR 60.4. In particular, the EPA is proposing to include a sentence in 40 CFR 60.5362c(a) that reads as follows: ''The submission of such plan shall be made in electronic format according with 40 CFR 60.5362c(d) of this subpart.'' In 40 CFR 60.5362c(d), the EPA is proposing the requirements associated with the electronic submittal of plans.

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[296] For more information about the EPA's pre-proposal outreach activities, please see EPA Docket ID No. EPA–HQ–OAR–2021–0295 and EPA–HQ–OAR–2021–0317. For a description of the themes that commenters raised please see the 2021 November proposal at 86 FR 63143.

[297] *https://www.epa.gov/sites/default/files/2021-05/documents/us_epa_training_webinar_on_oil_and_natural_gas_for_communities.5.27.2021.pdf.*

[298] June 15, 2021 session: *https://youtu.be/T8XwDbf-B8g; June 16, 2021.* session: *https://www.youtube.com/watch?v=l23bKPF-5oc;* June 17, 2021 session: *https://www.youtube.com/watch?v=R2AZrmfuAXQ.*

[299] Full transcripts for the listening sessions are posted at EPA Docket ID No. EPA–HQ–OAR–2021–0295.

As previously described, CAA section 111(d) requires the EPA to promulgate a ''procedure'' similar to that of CAA section 110 under which states submit plans. The statute does not prescribe a specific platform for plan submissions, and the EPA reasonably interprets the procedure it must promulgate under the statute as allowing it to require electronic submission. Requiring electronic submission is reasonable for the following reasons. Providing for electronic submittal of CAA section 111(d) state plans in EG OOOOc in place of paper submittals aligns with current trends in electronic data management and will result in less burden on the states. It is the EPA's experience that the electronic submittal of information increases the ease and efficiency of data submittal and data accessibility. The EPA's experience with the electronic submittal process for SIPs under CAA section 110 has been successful as all the states are now using the State Planning Electronic Collaboration System (SPeCS). SPeCS is a user-friendly, web-based system that enables state air agencies to officially submit SIPs and associated information electronically for review and approval to meet their CAA obligations related to attaining and maintaining the NAAQS. SPeCS is the EPA's preferred method for receiving such SIPs submissions. The EPA has worked extensively with state air agency representatives and partnered with E-Enterprise for the Environment and the Environmental Council of the States to develop this integrated electronic submission, review, and tracking system for SIPs. SPeCS can be accessed by the states through the CDX. The CDX is the Agency's electronic reporting site and performs functions for receiving acceptable data in various formats. The CDX registration site supports the requirements and procedures set forth under the EPA's Cross-Media Electronic Reporting Regulation, 40 CFR part 3.

The EPA is proposing to include the requirements associated with the electronic submittal of a state plan in EG OOOOc. As proposed, EG OOOOc will require state plan submission to the EPA be via the use of SPeCS or through an analogous electronic reporting tool provided by the EPA for the submission of any plan required by this subpart. The EPA is also proposing to include language to specify that states are not to transmit CBI through SPeCS. Even though state plans submitted to the EPA for review and approval pursuant to CAA section 111(d) through SPeCS are not to contain CBI, this language will also address the submittal of CBI in the event there is a need for such information to be submitted to the EPA. The requirements for electronic submission of CAA section 111(d) state plans in EG OOOOc will ensure that these Federal records are created, retained, and maintained in electronic format. Electronic submittal will also improve the Agency's efficiency and effectiveness in the receipt and review of state plans. The electronic submittal of state plans may also provide continuity in the event of a disaster like the one our nation experienced with COVID–19. The EPA requests comment on whether the EPA should provide for electronic submittals of plans as an option instead of as a requirement. The EPA requests comment on whether a requirement for electronic submissions of CAA section 111(d) state plans should be via SPeCS or whether another electronic mechanism should be considered as appropriate for CAA section 111(d) state plan submittals.

D. Timing of State Plan Submissions and Compliance Times

Background and Court Decision Re: Vacated Timelines. Under CAA section 111(d), it is first the EPA's responsibility to establish a BSER and a presumptive level of stringency via a promulgated EG. It is then each state's obligation to submit a plan to the EPA that establishes standards of performance for each designated facility. The EPA acknowledged in the November 2021 proposal that the D.C. Circuit vacated certain timing provisions within 40 CFR part 60, subpart Ba. *Am. Lung Assoc.* v. *EPA,* 985 F.3d at 991 (D.C. Cir. 2021) (*ALA*). See 86 FR 63255 (November 15, 2021). These vacated timing requirements include: the timeline for state plan submissions, the timeline for the EPA to act on a state plan, the timeline for the EPA to promulgate a Federal plan, and the timeline that dictates when state plans must include increments of progress. As a result of the court's vacatur, no regulations currently govern the timing of these actions for EGs promulgated after July 8, 2019.[300] The Agency plans to undertake a separate rulemaking to address these vacated provisions in subpart Ba for purposes of the implementing regulations, including a generally applicable deadline for state plan submissions. However, the EPA solicited comment in the November 2021 proposal on any facts and circumstances that are unique to the oil and natural gas industry that the EPA should consider when proposing a timeline for plan submission applicable to a final EG for this source category. The EPA is now proposing to require that each state adopt and submit to the Administrator, within 18 months after publication of the final EG OOOOc, a plan for the control of GHGs in the form of limitations on methane to which EG OOOOc applies. As described further in this section, an 18-month deadline for state plans addressing EG OOOOc both appropriately accommodates the process required by states to develop plans to effectuate the EG OOOOc, and is consistent with the objective of CAA section 111(d) to ensure that designated facilities control emissions of GHGs that the EPA has determined may be reasonably anticipated to endanger public health or welfare.

The EPA notes that the portions of the implementing regulations under subpart Ba that were not affected by the court's vacatur, the November 2021 proposal, and this supplemental proposal collectively lay out all of the required components of, and requirements for, state plans for purposes of EG OOOOc. Therefore, states will have the necessary information at that time to develop state plans to meet the requirements of any final EG OOOOc. Any separate rulemaking to address the vacated provisions in subpart Ba will not add to or change these required components. The EPA intends to propose deadlines for its action on state plan submissions and for promulgation of a Federal plan in its separate rulemaking. These deadlines are intended to apply generally to these actions implementing EGs under CAA section 111(d), including to the EPA's action on state plan submissions and promulgation of a Federal plan under the final EG OOOOc. It is not necessary for the EPA to propose deadlines on its own action on state plans submitted in response to a final EG OOOOc, or promulgation of a Federal plan where a state fails to submit an approvable plan, as part of this supplemental proposal because these deadlines are not relevant to states in the development of their plans, and go to the EPA's actions subsequent to the states' development of their plans. However, the EPA intends to propose and finalize these deadlines not later than finalization of an EG OOOOc, so that states and stakeholders will have knowledge of them as development on state plans begins. Additionally, as described further in this section, the EPA is proposing the final compliance schedule for designated facilities to run from the deadline for state plan submissions. Accordingly, the compliance deadline for any final EG

[300] The court did not vacate the applicability provision for subpart Ba under 40 CFR 60.20a(a).

OOOOc will also be knowable and provide certainty of obligations to regulated entities and other stakeholders in advance of state plan development. The D.C. Circuit's vacatur of the extended timelines in subpart Ba was based both on the EPA's failure to substantiate the necessity for the additional time at each step of the administrative process, and the EPA's failure to address how those extended implementation timelines would impact public health and welfare. Accordingly, for EG OOOOc, the EPA has evaluated these factors and is proposing the 18-month state plan deadline based on the minimum administrative time reasonably necessary for each step in the implementation process thus, minimizing impacts on public health and welfare. This approach addresses both aspects of the *ALA* decision because states will take no longer than necessary to develop and adopt plans that impose requirements consistent with the overall objectives of CAA section 111(d).

The EPA acknowledges this proposed 18-month deadline is not identical to the generally applicable three year-deadline for SIPs under CAA section 110, which the agency adopted in the vacated subpart Ba rule. However, the EPA's proposed deadline is consistent with the requirement of CAA section 111(d) that the EPA to promulgate a procedure ''similar'' to that of CAA section 110, rather than an identical procedure. This is also consistent with the *ALA* decision, which requires the EPA to ''engage meaningfully with the different scale'' of CAA section 111(d) and 110 plans. *Am. Lung Ass'n* v. *EPA,* 985 F.3d 914, 993 (D.C. Cir. 2021). Accordingly, the EPA evaluated each step of the OOOOc implementation process to independently determine the appropriate duration of time to accomplish the given step as part of the overall process, and the proposed timeline represents what the EPA is proposing to determine will be necessary for a state plan upon publication of any final EG OOOOc.

As described previously, no timing requirements for state plan submissions are currently in effect for EGs published after July 8, 2019. The original implementing regulations promulgated under subpart B in 1975, which are applicable to EGs published before July 8, 2019, provide that states have nine months to submit a state plan after publication of a final EG. 40 CFR 60.23(a)(1). In 2019, the EPA promulgated subpart Ba and provided three years for states to submit plans, consistent with the timelines provided for submission of SIPs pursuant to CAA section 110(a)(1). This 3-year timeframe was vacated in the *ALA* decision, and thus currently there is no applicable deadline for state plan submissions required under EGs subject to subpart Ba. In evaluating the appropriate timeline for plan submittal to propose for EG OOOOc, the EPA reviewed steps that states need to carry out to develop, adopt, and submit a state plan to the EPA, and its history in implementing EGs under the timing provisions of subpart B. The EPA further evaluated statutory deadlines, contents, and processes for relatively comparable state plans under CAA sections 129 and 182. The EPA also considered the characteristics of the Crude Oil and Natural Gas source category to assist justification for the timelines and address how the timeline will impact health and welfare.

In developing a CAA section 111(d) state plan, a state must consider multiple components in meeting applicable requirements. In addition to any requirements that an EG specifies for state plans, subpart Ba specifies certain fundamental elements that must be included in a state plan submission (see 40 CFR 60.24a, 60.25a, 60.26a) and certain processes that a state plan must undergo in adopting and submitting a plan (see 40 CFR 60.23a). In addition to these EPA requirements for state plans, there are also state-specific processes applicable to the development and adoption of a state plan. In particular, the component that the EPA expects to take the most time and have the most variability from state to state is the administrative process (*e.g.,* through legislative processes, regulation, or permits) that establishes standards of performance. Considering this variability, 18 months should adequately accommodate the differences in state processes necessary for the development of a state plan that meets applicable requirements. The EPA evaluated data from previously implemented EGs, and the statutory deadlines and data from analogous programs (*i.e.,* CAA section 129), as described below, to help inform this proposed 18-month timeline.

Subpart B provides nine months for states to submit plans after publication of a final EG. The EPA's review of state's timeliness for submitting CAA section 111(d) plans under the 9-month timeline indicates that most states either did not submit plans or submitted plans that were substantially late. We note that the plans submitted under subpart B were not subject to the additional requirements the EPA is proposing for meaningful engagement and consideration of RULOF, respectively described in section V.B. Based on the lack of timeliness of prior state plan submissions under subpart B and the additional requirements of this proposal, EG OOOOc, nine months is not a suitable amount of time for most states to adequately develop a plan for an EG.

To help inform what is an appropriate proposal for the state plan submission deadline, the EPA also reviewed CAA section 129's statutory deadline and requirements for state plans, and the timeliness and responsiveness of states under CAA section 129 EGs. CAA section 129 references CAA section 111(d) in many instances, creating considerable overlap in the functionality of the programs. Notably, existing solid waste incineration units are subject to the requirements of both CAA sections 129 and 111(d). CAA section 129(b)(1). The processes for CAA sections 111(d) and 129 are very similar in that states are required to submit plans to implement and enforce the EPA's EGs. However, there are some key distinctions between the two programs, most notably that CAA section 129(b)(2) specifies that state plans be submitted no later than 1 year from the promulgation of a corresponding EG, whereas the statute does not specify a particular timeline for state plan submissions under CAA section 111(d) and is instead governed by the EPA's implementing regulations (*i.e.,* subparts B and Ba). Moreover, CAA section 129 plans are required by statute to be at least as protective as the EPA's EGs. However, CAA section 111(d) permits states to take into account remaining useful life and other factors, which suggests that the development of a CAA section 111(d) plan could involve more complicated analyses than a CAA section 129 plan (see section V.B. for more information on RULOF provisions). The contrast between the CAA section 129 plans and CAA section 111(d) plans suggests that in determining the timeframe for CAA section 111(d) plan submissions the EPA should provide for a longer timeframe than the 1 year timeframe the statute provides under CAA section 129.

The EPA found that a considerable number of states have not made required state plan submissions in response to a CAA section 129 EG. In instances where states submitted CAA section 129 plans, a significant number of states submitted plans between 14 to 17 months after the promulgated EG. This suggests that states will typically need more than 1 year to develop a state plan to implement an EG, particularly for a program that permits more source-specific analysis than under CAA section 129 as CAA section 111(d) does.

In the 2019 promulgation of subpart Ba, the EPA mirrored CAA section 110 by giving states 3 years to submit plans. As previously described, the court partly faulted the EPA for adopting the CAA section 110 timelines without accounting for the differences in scale and scope between CAA section 110 and 111(d) plans. The EPA has now more closely evaluated the statutory deadlines and requirements in the CAA section 110 implementation context to determine what might be feasible for an OOOOc EG state plan submission timeline. The EPA specifically focused on statutory SIP submission deadline and requirements in the context of attainment plans for the ozone NAAQS. Subpart 2 of Title I of the CAA contains a number of deadlines for ozone attainment plans that are 2 years or longer. For example, areas initially designated Marginal have two years from designation to submit a SIP that contains a permitting program and emissions inventory. CAA section 182(a). Areas initially designated Moderate have two years to submit a plan implementing reasonable available control technologies under CAA section 182(b)(2)), and three years to submit their attainment plan and other requirements under CAA section 182(b)(1). These ozone attainment plans are arguably more complicated for states to develop when compared to plans under CAA section 111(d) for EG OOOOc. For example, ozone attainment plans require states to determine how to control a variety of sources, based on extensive modeling and analyses, in order to bring a nonattainment area into attainment of the NAAQS by a specified attainment date. Under CAA section 111(d) and EG OOOOc, it is clear which designated facilities must be subject to a state plan, and the standards of performance for these sources must generally reflect the level of stringency determined by the EG unless a state chooses to account for RULOF. Additionally, ozone attainment plans must contain inventories of actual emissions from certain sources, whereas the EPA is proposing to supersede the subpart Ba inventory requirement for purposes of this EG. The difference in complexity between the CAA ozone attainment plan requirements and the plan requirements for EG OOOOc suggests that a timeline of 18 months is more appropriate for developing state plans submissions in response to this EG.

Furthermore, the EPA considered the characteristics of the Crude Oil and Natural Gas source category. The EPA believes that EG OOOOc has the potential to require states to perform considerable engineering and/or economic analyses for their plan. For example, the EPA anticipates considerable engineering analyses for when states chose to leverage their existing state programs and determine that their existing state program meets the criteria to conduct a source-by-source stringency comparison. The engineering analysis can become more complex should a state chooses to utilize a different design, equipment, work practice, and/or operational standard than the EG because a qualitative assessment will have a number of metrics that require evaluation. The EPA also anticipates states will need to conduct considerable engineering and economic analysis should a state invoke RULOF. As discussed in section V.C., when invoking RULOF, the plan submission must identify all control technologies available for the source and evaluate the BSER factors for each technology, using the same metrics and evaluating them in the same manner as the EPA did in developing the EG. For example, if the EPA considered capital cost as part of the BSER analysis, the state will also need to consider the same.

The EPA has long recognized the unique nature of the Crude Oil and Natural Gas source category because, in comparison to other EG, it is geographically spread out covering multiple industry segments. Specifically, 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.[301] The Crude Oil and Natural Gas source category impacts a great number of states, tribes, and U.S. territories in some capacity. U.S. Energy Information Administration (EIA) production data shows thirty-four states that have crude oil and or natural gas production.[302] Except for Vermont and Hawaii, the states not producing crude oil and or natural gas have compressor stations in the transmission and storage segment. The EPA understands that EG OOOOc for the Crude Oil and Natural Gas source category will apply to an extraordinary number of designated facilities and for many designated facilities the standards are complex compared to other EG. For example, in the U.S., the EPA has identified over 15,000 oil and gas owners and operators, around 1 million producing onshore oil and gas wells, about 5,000 gathering and boosting facilities, over 650 natural gas processing facilities, and about 1,400 transmission compression facilities. States will need to develop and draft plans covering these designated facilities that include the required components, such as standards of performance and implementation measures for such standards, and adopt the plans through their required administrative processes before submitting them to the EPA. EG OOOOc covers numerous designated facilities with corresponding presumptive standards. By comparison, the EPA's EG for Municipal Solid Waste Landfills included one designated facility type, affecting approximately 1,000 landfills. 81 FR 59313 (August 29, 2016). Of these 1,000 landfills, approximately 731 will be affected by the collection and control standard laid out in the rule, approximately 93 more landfills than the 1996 Municipal Solid Waste Landfills EG. 61 FR 9919 (March 12, 1996).

The EPA also recognizes the need to address potential health and welfare impacts of methane emissions from this source category. The EPA discusses extensively in section III of the November 2021 proposal[303] titled, ''Air Emissions from the Crude Oil and Natural Gas Sector and Public Health and Welfare,'' and in section VI of the November 2021 proposal titled, ''Environmental Justice Considerations, Implications, and Stakeholder Outreach,'' the urgent need to mitigate climate-destabilizing pollution and protecting human health by reducing GHG emissions from the Oil and Natural Gas Industry,[304] specifically, the Crude Oil and Natural Gas source category.[305]

[301] For purposes of the November 2021 proposal and this supplemental 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''.

[302] See *https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm* and *https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm.*

[303] See 86 FR 63110 (November 15, 2021).

[304] The EPA characterizes the Oil and Natural Gas Industry operations as being generally composed of four segments: (1) Extraction and production of crude oil and natural gas (''oil and natural gas production''), (2) natural gas processing, (3) natural gas transmission and storage, and (4) natural gas distribution.

[305] The EPA defines the Crude Oil and Natural Gas source category to mean: (1) Crude oil production, which includes the well and extends to

Continued

The Oil and Natural Gas Industry is the United States' largest industrial emitter of methane, a highly potent GHG. Human activity-related emissions of methane are responsible for about one third of the warming due to well-mixed GHGs and constitute the second most important warming agent arising from human activity after carbon dioxide (a well-mixed gas is one with an atmospheric lifetime longer than a year or two, which allows the gas to be mixed around the world, meaning that the location of emission of the gas has little importance in terms of its impacts). According to the Intergovernmental Panel on Climate Change (IPCC), strong, rapid, and sustained methane reductions are critical to reducing near-term disruption of the climate system and are a vital complement to reductions in other GHGs that are needed to limit the long-term extent of climate change and its destructive impacts. The need to balance the complexity of EG OOOOc and the need to mitigate climate change and protecting human health further suggest that a timeline of 18 months is more appropriate for development of state plans submissions.

Thus, based on the EPA's evaluation of states' responsiveness to previous CAA section 111(d) EGs, the contrast between the development of CAA section 111(d) plans and CAA section 129 plans, the complexity of the source category and designated facilities, and the need to quickly take action to address critical climate and health and welfare impacts, the EPA is proposing to require that state plans under EG OOOOc be due 18 months after publication of the final EG. This proposed timeframe is substantially shorter than the 3-year deadline vacated by the D.C. Circuit; however, it should give states adequate time to adopt and submit approvable plans without extending the timing such that significant adverse impacts to health and welfare are likely to occur from the foregone emission reductions during the state planning process. Allowing states sufficient time to develop feasible implementation plans for their designated facilities that adequately address public health and environmental objectives will ultimately help ensure timelier implementation of EG OOOOc, and therefore achievement in actual emission reductions, than would an unattainable deadline that may result in the failure of states to submit plans and require the development and implementation of a Federal plan.

The EPA recognizes that the court, in *ALA,* faulted the Agency for failing to consider the potential impacts to public health and welfare associated with extending planning deadlines. The EPA does not interpret the court's direction to require a quantitative measure of impact, but rather consideration of the importance of the public health and welfare goals when determining appropriate deadlines for implementation of regulations under CAA section 111(d). Because 18 months is the minimum period of time in which the EPA finds that most states can expeditiously create and submit a plan that meets applicable requirements for EG OOOOc, it follows that the EPA has appropriately considered the potential impacts to public health and welfare associated with this extension of time by providing no more time than the states reasonably need to ensure a plan is comprehensive and timely. The EPA is soliciting comment on the proposed 18-month state plan submission deadline upon publication of the final EG OOOOc, and the analysis supporting the EPA's proposed determination regarding the amount of time reasonably necessary for plan development and submission. The EPA is also soliciting comment on whether the EPA should consider any other factors in setting this deadline.

As discussed in section V.B of this preamble, the EPA is proposing to include a requirement for states to undertake outreach and meaningful engagement with pertinent stakeholders as part of the state plan development process. The EPA solicits comment on how much, if any, time this additional engagement will take in the state plan development process.

In section V.B of this preamble, the EPA is also proposing revisions to the RULOF provision. These proposed revisions would clarify the procedures for considering RULOF by establishing a robust analytical framework that would require a state to provide a sufficient justification when applying a standard of performance that is less stringent than the EPA's presumptive level of stringency, thereby allowing the EPA to readily determine if the state's plan is satisfactory and therefore approvable. The proposed state plan submission timeline of 18 months should adequately provide time for states to conduct the analyses required by this provision; however, the EPA is soliciting comment on whether states will need additional time in the plan development to account for instances where RULOF is considered. The EPA is specifically requesting comment on how much additional time might be required for this consideration and how that additional time fits within the entire process of state plan development.

The proposed state plan submission timeline should be generally achievable by states. The EPA notes it is obligated to promulgate a Federal plan for states that have not submitted a plan by the submission deadline. Once the obligation to promulgate a Federal plan is triggered, it can only be tolled by the EPA's approval of a state plan. If a Federal plan is promulgated, a state may still submit a plan to replace the Federal plan. A Federal plan under CAA section 111(d) is a means to ensure timely implementation of EGs, and a state may choose to accept a Federal plan for their sources rather than submit a state plan. While the EPA encourages states to timely submit plans, there are no mandatory sanctions associated with submitting a late plan or accepting the implementation of a Federal plan.

Timeline for State Plan Compliance Schedule. Under 40 CFR 60.22a(b)(5), the EPA in an EG is required to provide, among other things, ''the time within which compliance with standards of performance can be achieved''. Each state plan must then include compliance schedules that, subject to certain exception, require compliance as expeditiously as practicable but no later than the compliance times included in the relevant EG. Id. at 60.24a(a) and (c). States are free to include compliance times in their plans that are earlier than those included in the final EG. *Id.* at 40 CFR 60.24a(f)(2). If a state chooses to include a compliance schedule in its plan that extends for a certain period beyond the date required for submittal of the plan, then ''the plan must include legally enforceable increments of progress to achieve compliance for each designated facility.'' 341 Id. at 40 CFR 60.24a(d). To the extent a state accounts for remaining useful life and other factors in applying a less stringent standard of performance than required by the EPA in the final EG, the state must also include a compliance deadline that it can demonstrate appropriately correlates with that standard.

The November 2021 proposal proposed requiring that state plans impose a compliance timeline on

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 this 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''.

designated facilities to require final compliance with the standards of performance as expeditiously as practicable, but no later than 2 years following the state plan submittal deadline. 86 FR 63256 (November 15, 2021). Commenters on the proposal indicated that more than 2 years after the submittal of a state plan was needed to come into compliance for existing sources. Given the number of designated facilities that would need to come into compliance, commenters explained that requiring existing sources to upgrade at the same time would place a substantial burden on the supply chain (all orders at the same time) and vendors (all install at the same time). Commenters stated that, if compliance timelines are too short, there will be significant economic disruptions for both the companies operating these facilities as well as the manufacturers who support them. Commenters also stated that there would be a need to train a tremendous number of staff on the regulatory requirements and actions needed to comply. A few of the commenters representing states also noted that 2 years from state plan submittal would not allow sufficient time for states to issue the air quality permits in advance of the compliance date for the sources to have regulatory requirements with which to demonstrate compliance. Environmental commenters supported the EPA's proposed requirement that state plans include a compliance timeline within no more than 2 years of plan submission and urged the Agency to consider whether a more abbreviated compliance timeline is warranted.[306]

In evaluating whether to revise the November 2021 proposed two-year final compliance deadline, the EPA considered several factors that could impact the ability of a designated facility to come into compliance with the proposed presumptive standards. These factors are presented in Table 38.

TABLE 38—FACTORS CONSIDERED WHEN DETERMINING COMPLIANCE TIMELINE

Factor	Description
Design/Purchase Equipment	Equipment must be purchased and installed to comply. This could be control equipment or specific equipment to meet an equipment standard (*e.g.,* solar powered pneumatic controller). This would also typically involve design considerations.
Availability of Equipment (Supply Chain Issues)	This factor is related to the potential shortage of available equipment. Note that this could have an impact on small businesses as the assumption is that larger businesses would be supplied first.
Cost of Equipment (Individual Designated Facility)	The cost of equipment for an individual designated facility. This cost may disproportionally impact small businesses.
Performance Testing	The requirement for a performance testing requires securing the services of a testing contractor, scheduling and planning the test, and notifying/coordinating with the state agency. In addition to control device performance testing, this would also include monitoring (*e.g.,* fugitive component monitoring).
Complexity of Requirements	More complex requirements may need more time for owners and operators to understand the requirements and develop procedures upfront to ensure initial and continuing compliance.
Availability of Specialized Services (Monitoring)	This is related to the potential shortage of available specialized services (*e.g.,* OGI contractors). Note that this could have an impact on small businesses as the assumption is that contractors could prioritize larger businesses.
Number of Designated Facilities	The sheer number of designated facilities may have an impact on the ability to comply within a specified timeline, which assumes that it will potentially be more problematic for companies owning many designated facilities to comply in a shorter time frame.
Existing Sources Covered by State Regulation	If the designated facility is covered by state regulations that cover existing sources to a degree equivalent to the EG, the number of designated facilities needing to comply with be less.
Emissions Reduced/Total Designated Facility	The overall methane emissions reduction that will result from control of existing sources under the EG. EPA could prioritize designated facilities to achieve emission reductions sooner.

Some of the factors presented in Table 38 would impact the ability of an owner or operator of a designated facility to comply within two years more than others. For example, factors that are beyond an owner or operator's control, such as the availability of specialized services and availability of equipment, can be compounded by the fact that there are a large number of designated facilities where owners or operators are dependent on the availability of equipment and services. Other factors, such as the cost of equipment necessary for a designated facility to come into compliance, will impact some owners and operators more than others. Small businesses have often reported that large businesses generally have an advantage over small businesses in such cases. Presumptive standards that include a higher reliance on factors that would impact the ability of a designated facility to come into compliance, such as those proposed for pneumatic controllers, were considered to require more time (*i.e.,* greater than the November 2021 proposed 2-year time frame). For example, to meet the proposed presumptive standards for pneumatic controllers, it is expected that more time may be needed due to the anticipated high demand for specialized equipment to meet the proposed EG standards and the increased reliance on ''design/purchase equipment'', ''availability of equipment'', ''cost of equipment,'' and ''number of designated facilities.'' Other

[306] See Document ID No. EPA–HQ–OAR–2021–0317–0844.

designated facility presumptive standards that are less dependent on the need for specialized equipment or services (*e.g.,* fugitive emissions work practice standards) might require less time to come into compliance than pneumatic controllers but would still require considerable upfront planning based on the number of designated facilities.

After consideration of comments received on the November 2021 proposal and consideration of the factors that could impact the ability of a designated facility to come into compliance with the proposed presumptive standards, the EPA is proposing to require that state plans impose a compliance timeline on designated facilities to require final compliance with the standards of performance as expeditiously as practicable, but no later than 36 months following the state plan submittal deadline. The EPA considered requiring differing compliance timelines for the differing designated facilities depending on the requirements of the proposed presumptive standards and the factors presented in Table 38 but chose to include a uniform compliance timeframe for all of the designated facilities. The EPA believes that establishing a uniform compliance timeline of no later than 36 months following the state plan submittal deadline simplifies compliance and eases the burden on large and small business owners and operators that need to develop and implement plans to meet their compliance obligations for a large number of designated facilities. The required state plan compliance elements for owners and operators to come into compliance include the need to: (1) Become familiar with state plan requirements for the nine different types of designated facilities, (2) assess all existing sites and operations owned by the company to determine the universe of designated facilities that are subject to requirements, (3) prepare an increment of progress final control compliance plan for meeting standards of performance for all of the hundreds, potentially thousands, of designated facilities owned by the company, (4) implement a compliance plan for each designated facility, (5) ensure standards of performance for designated facility are met by required compliance dates, and (6) plan and implement initial compliance performance testing, monitoring, recordkeeping, and reporting. Each of the nine types of designated facilities include various compliance element needs (*e.g.,* engineering assessments, requirements to purchase equipment, contract services for modifying existing equipment to include add-on control equipment, contract services to perform monitoring and/or performance testing, contract services to perform maintenance and repair services to ensure compliance).

The level of planning and implementation of a plan to come into compliance will differ by each type of designated facility. Further, site-specific conditions may require different compliance paths even for the same type of designated facility. Another factor to consider is the ability of an owner or operator to meet the initial capital and labor expenditures needed to develop and implement a compliance plan will vary based on the numbers of each of the designated facilities and available capital and in-house expertise/labor. Small businesses often need more time to absorb the associated capital and labor expenditure needs to develop and implement compliance plans. By allowing a uniform compliance deadline of 36 months from the time of submittal of the state plan to come into compliance, owners and operators are able to take into consideration all of the differing designated facilities, sites and expenditures that will be needed to comply when they develop their compliance plans. This will also reduce any potential confusion that could occur with varied compliance deadlines for designated facilities that are covered under the proposed EG.

As previously described, EPA is proposing to require that states submit their state plan within 18 months of publication of the EGs. Accordingly, linking a 36-month compliance deadline to the state plan submittal deadline for purposes of this EG would give sources ample time to plan for compliance with an approved state plan. The EPA also notes that publication of a final EG will also give sources meaningful information as to their potential compliance obligations, such as the presumptive standards, in advance of the state plan submittal deadline. Though EPA has not yet proposed a timeline for its action on state plans in response to the *ALA* vacatur, and intends to do so in an upcoming rulemaking, such timeline cannot be so lengthy as to contravene the court's direction to consider potential health and welfare impacts of an extended deadline. The EPA believes that a compliance deadline 36 months from the state plan submittal deadline is an appropriate amount of time for designated facilities to ensure compliance based on the EPA's general understanding of the industry and the proposed presumptive standards and accounts for retrofit considerations and potential supply chain issues that owners and operators may encounter. The EPA considered whether to link the compliance deadline to its approval of a state plan, however, requiring compliance with state plans based on the state plan submittal deadline rather than the state plan approval date standardizes when designated facilities must come into compliance across states.

Subpart Ba requires that standards of performance are implemented in a timely manner through provisions that require legally enforceable increments of progress if the compliance schedule extends beyond 24 months after the state plan submission deadline.[307] However, the 24-month timeline for triggering increments of progress was vacated by the D.C. Circuit in the *ALA* decision. Petitioners did not challenge, and the court did not vacate, the substantive requirement for increments of progress. The EPA intends to address the vacated timeline for increments of progress for purposes of the implementing regulations in an upcoming rulemaking. For EG OOOOc, because the EPA is proposing a final compliance deadline of 36 months after publication of the EG, the EPA is proposing to require that state plans must include legally enforceable increments of progress in order to better assure compliance by each designated facility or category of facilities. While the EPA is proposing 36 months after the state plan submission deadline for final compliance based on the considerations described above, increments of progress will help assure that designated facilities are on track to actually achieve compliance by undertaking certain concrete interim steps. Taking into consideration the large numbers of designated facilities that regulated entities would need to evaluate and plan for to come into compliance, we are proposing that state plans require owners and operators of designated facilities address two of the five incremental of progress steps identified in the definition of increments of progress subpart Ba: (1) A final control plan and (2) final compliance. The EPA is proposing that the final control plan include a compliance plan for each designated facility, but a company would be allowed to submit one plan that covers all of the company's designated facilities in the state in lieu of submitting a plan for each designated facility. The final control plan would be

[307] 40 CFR 60.24a(a) and 60.24a(d).

required to include an identification of their designated facilities and how they are planning to comply with the EGs for each of their designated facilities (*e.g.,* air pollution control devices/measures to be used to comply with the emission limits, standards and other requirements). The final control plan would also be required to include all instances where a designated facility is complying with an alternative standard (*e.g.,* routing centrifugal compressor wet seal emissions to a control device to achieve a 95 percent reduction in methane instead of complying with the 3 scfm volumetric flow rate standard) or when the owner or operator is planning to claim technical infeasibility to allow compliance with an alternative standard (*e.g.,* a pneumatic pump that demonstrates it is technically infeasible to use a pump that is not driven by natural gas and that is technically infeasible to route to control). We are proposing that the final control plan be required to be submitted within two years after the deadline for the state plan submittals. This timeline allows sufficient time for regulated entities to develop their compliance plan for each of their designated facilities to meet their compliance obligations. The EPA solicits comment on the timing and requirements of this final control plan proposal.

In addition to the final control plan, we evaluated whether to require a report that demonstrates final compliance as an increment of progress report. We are proposing that state plans include a requirement for owners and operators of designated facilities to submit a notification of final compliance report for each designated facility on or before 60 days after the compliance date of the state plan. Under this proposal, a company would be allowed to submit one notification that covers all of the company's designated facilities in a state in lieu of submitting a notification for each designated facility. As an alternative, we evaluated not including a specific requirement for a notification of final compliance report. Without a requirement for a notification of final compliance report, confirmation that designated facilities are complying with a state plan would not occur until the first annual report. The EPA determined that requiring a notification of final compliance report that was submitted before the first annual report was more closely aligned with the intent of a final compliance increment of progress step. The EPA solicits comment on this proposed notification of final compliance report.

VI. Use of Optical Gas Imaging in Leak Detection (Appendix K)

A. Overview of the November 2021 Proposal

In the November 2021 proposal, the EPA proposed a protocol for the use of OGI in the determination of leaks as Appendix K. The protocol was proposed for use in the oil and gas sector but was proposed to have broader applicability to surveys of process equipment using OGI cameras throughout the entire oil and gas upstream and downstream sectors from production through refining to distribution where a subpart in those sectors references its use.

The proposed appendix K was based on extensive literature review on the technology development, as well as observations on current applications of OGI technology, multiple empirical laboratory studies and OGI technology evaluations commissioned by the EPA, and a virtual stakeholder workshop hosted by the EPA to gather input on development of a protocol for the use of OGI. The proposed appendix K outlined the procedures that camera operators would be required to follow to identify leaks or fugitive emissions using a field portable infrared camera. Additionally, the proposed appendix K contained specifications relating to the required performance of OGI cameras, required operator training and verification, determination of an operating window for performing surveys, and requirements for a monitoring plan and recordkeeping.

B. Significant Changes Since Proposal

1. Scope

The EPA proposed that appendix K would have broad applicability across the oil and gas upstream and downstream sectors, but that it must be referenced by an applicable subpart before it would apply. This would potentially include well sites, compressor stations, boosting stations, petroleum refineries, gas processing plants, and gasoline distribution facilities. Chemical plants and other facilities outside of the oil and gas upstream and downstream sectors were specifically excluded in the applicability section.

Commenters stated that appendix K applicability should not be restricted to the oil and gas upstream and downstream sectors.[308] While the EPA originally excluded the chemical sector because there are issues with seeing some of the compounds that could be released as emissions in some of the chemical sector sources, there are some chemical sector sources where most of the emissions are made up of compounds that can be imagined by an OGI camera. As such, the EPA is proposing to revise the scope and applicability for appendix K to remove the sector applicability and to base the applicability on being able to image most of the compounds in the gaseous emissions from the process equipment. The EPA is retaining the requirement that appendix K does not on its own apply to anyone but must be referenced by a subpart before it would apply.

2. Operator Training

The EPA proposed a multi-layered training requirement for OGI camera operators because operator training is critical in developing the ability to see leaks with an OGI camera. The proposed training consisted of both an initial and annual classroom training on the fundamental concepts of OGI, basic operation of the camera, best practices for finding leaks, and the site's monitoring plan. appendix K also contained initial field training consisting of 100 site surveys with a senior OGI camera operator, where initially the trainee observes the senior OGI camera operator and then eventually is observed by the senior OGI camera operator, and a final site survey test with zero missed persistent leaks. Additionally, the EPA proposed quarterly performance audits for OGI camera operators either by comparative monitoring or a review of video footage by a senior OGI camera operator, where the auditee must have zero missed persistent leaks and a technique that aligns with the site's monitoring plan. Auditees not meeting these criteria must be retrained. The EPA also proposed that operators would be required to repeat initial training after 12 months of inactivity.

The EPA received numerous comments on all aspects of the proposed training requirements. Commenters stated that online training should be allowed for classroom training, and they recommended that periodic classroom training should be extended to every 2 or 3 years.[309] Commenters also provided a broad range of recommendations on what the initial field training should

[308] See Document ID Nos. EPA–HQ–OAR–2021–0317–0604, EPA–HQ–OAR–2021–0317–0748, EPA–HQ–OAR–2021–0317–0808, and EPA–HQ–OAR–2021–0317–0831.

[309] See Document ID Nos. EPA–HQ–OAR–2021–0317–0561, EPA–HQ–OAR–2021–0317–0793, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0814, EPA–HQ–OAR–2021–0317–0831, EPA–HQ–OAR–2021–0317–0954, and EPA–HQ–OAR–2021–0317–1373.

look like.[310] The recommendations for initial training hours ranged from around 5 to 80 hours. Additionally, some commenters said the determination of suitability for independent monitoring should be based on observations and comparative monitoring, not on a set number of hours of training.[311] Some commenters suggested reducing the final survey test to 1 hour.[312] Commenters also suggested that requiring zero missed leaks during the final survey test was too stringent.[313] Some commenters thought the OGI camera operator audits were unnecessary, while others thought they were too frequent or too long. There was a range of recommendations on what the audit frequency should be, including annual or a stepped up and down frequency based on performance.[314] Additionally, commenters stated that requiring zero missed leaks during the audit was too stringent and that instead of a failed audit triggering automatic retraining, there should be an opportunity to counsel the auditee and let them try again.[315] Commenters thought returning operators should only be required to take refresher level training, pass a performance audit, or pass the final survey test.[316] Commenters also thought there should be some grandfathering of current OGI camera operators.[317] Finally, commenters stated that there should be different performance audit and retraining requirements for small businesses and the Alaska North Slope.[318]

Based on these comments, the EPA is proposing specific revisions or clarifications related to the operator training requirements. In this action, the EPA is clarifying our intent to allow classroom training to be online or in-person and revising the classroom refresher training frequency to biennial (*i.e.,* every 2 years). For the initial field training, the EPA is proposing 30 survey hours with a senior OGI camera operator and changing the final field test from one site to two survey hours. The EPA is also proposing to allow up to 10 percent missed leaks on the final survey test if there are more than 10 leaks found by the senior OGI camera operator during the final field test and is providing clarification on what happens if a trainee doesn't pass the final field test. In this instance, the senior OGI camera operator would discuss the failure with the trainee and provide instruction on improving performance, then allow the trainee to repeat the test. While the EPA is retaining quarterly operator audits, we are proposing to reduce the audit from four hours to two hours and allow up to 10 percent missed leaks if there are more than 10 leaks found by the senior OGI camera operator during the audit. While an auditee would still need to retrain following a failed audit, the EPA is proposing to reduce the amount of retraining from 25 site surveys to 16 survey hours and adding a requirement that the senior OGI camera operator counsel the auditee on the reasons for the failure and how to improve surveying techniques. However, if an auditee fails two consecutive audits, the auditee will have to complete the initial training again. The EPA is also proposing to reduce the amount of training required for OGI operators who have been inoperative for an extended period from the initial training requirements to the retraining requirements.

Finally, the EPA is proposing to allow previous OGI experience to substitute for some of the initial training requirements within appendix K in order to recognize the experience of current OGI camera operators. Specifically, OGI camera operators with previous classroom training (either at a physical location or online) that covers the majority of the elements required by the initial classroom training required in appendix K prior to the finalization of appendix K will not need to complete the initial classroom training, but if the date of training is more than 2 years before the date that the appendix is finalized, the OGI camera operator will need to complete the biennial classroom training in lieu of the initial classroom training. Also, OGI camera operators who have 40 hours of experience over the 12 calendar months prior to the date that appendix K is finalized may substitute the retraining requirements, including the final monitoring survey test, for the initial field training requirements.

3. Senior OGI Camera Operator

The EPA proposed that a senior OGI camera operator is a camera operator who has conducted a minimum of 500 site surveys over their career, including at least 20 site surveys in the past year, and who has taken or developed the initial classroom training. Commenters were concerned that there may be a lack of available senior OGI camera operators, especially in the period right after finalization of appendix K.[319] Commenters also stated that the definition is too restrictive, and some were concerned there is no certification program.[320] Some commenters also recommended that senior OGI operators should be removed from the auditing process since they are auditing and training others.[321]

The EPA is proposing to change the definition of senior OGI camera operator to someone with 1400 survey hours over their career, including 40 hours in the past year. The 1400 survey hours is consistent with the level that experienced operators had during the studies on operator experience performed at the Methane Emissions Technology Evaluation Center (METEC) test site.[322] The study clearly showed a delineation of the detection capabilities of high experienced operators, with the high experienced operators detecting about 67 percent more leaks than other operators. The experience of the group of operators considered to be high experienced operators began at around 700 sites surveyed. The background

[310] See Document ID Nos. EPA–HQ–OAR–2021–0317–0463, EPA–HQ–OAR–2021–0317–0561, EPA–HQ–OAR–2021–0317–0608, EPA–HQ–OAR–2021–0317–0718, EPA–HQ–OAR–2021–0317–0749, EPA–HQ–OAR–2021–0317–0793, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0816, EPA–HQ–OAR–2021–0317–0831, and EPA–HQ–OAR–2021–0317–0934.

[311] See Document ID Nos. EPA–HQ–OAR–2021–0317–0608 and EPA–HQ–OAR–2021–0317–0718.

[312] See Document ID Nos. EPA–HQ–OAR–2021–0317–0808 and EPA–HQ–OAR–2021–0317–0831.

[313] See Document ID Nos. EPA–HQ–OAR–2021–0317–0599, EPA–HQ–OAR–2021–0317–0750, EPA–HQ–OAR–2021–0317–0782, EPA–HQ–OAR–2021–0317–0793, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0817, and EPA–HQ–OAR–2021–0317–0831.

[314] See Document ID Nos. EPA–HQ–OAR–2021–0317–0463, EPA–HQ–OAR–2021–0317–0561, EPA–HQ–OAR–2021–0317–0599, EPA–HQ–OAR–2021–0317–0608, EPA–HQ–OAR–2021–0317–0718, EPA–HQ–OAR–2021–0317–0749, EPA–HQ–OAR–2021–0317–0782, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0831, and EPA–HQ–OAR–2021–0317–0916.

[315] See Document ID Nos. EPA–HQ–OAR–2021–0317–0561, EPA–HQ–OAR–2021–0317–0599, EEPA–HQ–OAR–2021–0317–0749, EPA–HQ–OAR–2021–0317–0808, and EPA–HQ–OAR–2021–0317–0831.

[316] See Document ID Nos. EPA–HQ–OAR–2021–0317–0463, EPA–HQ–OAR–2021–0317–0608, EPA–HQ–OAR–2021–0317–0718, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0816, and EPA–HQ–OAR–2021–0317–0831.

[317] See Document ID Nos. EPA–HQ–OAR–2021–0317–0808 and EPA–HQ–OAR–2021–0317–0831.

[318] See Document ID Nos. EPA–HQ–OAR–2021–0317–0814, EPA–HQ–OAR–2021–0317–0916, and EPA–HQ–OAR–2021–0317–1373.

[319] See Document ID Nos. EPA–HQ–OAR–2021–0317–0599, EPA–HQ–OAR–2021–0317–0750, EPA–HQ–OAR–2021–0317–0782, and EPA–HQ–OAR–2021–0317–0831.

[320] See Document ID Nos. EPA–HQ–OAR–2021–0317–0599, EPA–HQ–OAR–2021–0317–0561, EPA–HQ–OAR–2021–0317–0608, EPA–HQ–OAR–2021–0317–0718, EPA–HQ–OAR–2021–0317–0750, EPA–HQ–OAR–2021–0317–0802, and EPA–HQ–OAR–2021–0317–0808.

[321] See Document ID Nos. EPA–HQ–OAR–2021–0317–0749, and EPA–HQ–OAR–2021–0317–0808.

[322] See Document ID No. EPA–HQ–OAR–2021–0317–0076.

document for the METEC study estimated experience at about four sites per day, which equates to about two hours per site. Therefore, based on the data used in the study, 700 sites should equate to about 1400 hours on average. Additionally, the EPA is clarifying that the hours spent by the senior OGI camera operator performing comparative monitoring, either as part of initial training, retraining, or auditing other OGI camera operators, can be included when determining the senior OGI camera operator's experience both over their career and the past 12 months.

4. Dwell Time

The EPA proposed that during a survey, OGI camera operators should view equipment from multiple angles. For each angle, the dwell time, the active time the operator is looking for potential leaks when the scene is in focus and steady, would need to be a minimum of 5 seconds per component in the field of view. Some commenters stated that there is no need to specify a dwell time, while other commenters said that the dwell time should be shorter.[323] Still other commenters stated that the dwell time requirement should be based on the scene and not on a per component basis.[324]

The EPA is proposing to change the dwell time per angle to two seconds per component in the field of view. This aligns closely with the estimated time to complete a monitoring survey in the analysis performed for onshore natural gas processing plants for the proposed NSPS OOOOb.[325] The EPA based that analysis on data provided by OGI camera operators. The EPA believes that two seconds per component would provide enough time to determine whether a leak is present, and it is expected that a trained OGI camera operator would be aware of situations that necessitate dwelling longer than the minimum required time.

5. Other Changes

The EPA proposed that OGI camera operators must take 5-minute rest breaks after 20 minutes of continuous surveying. This proposed requirement is the same as the requirement for opacity observations in EPA Method 9 of 40 CFR part 60 appendix A–4. Commenters were divided over this requirement. Some commenters agreed with the principal of rest breaks while requesting additional flexibility or longer surveying times between breaks. Others felt it was unnecessary to mandate rest breaks.[326] Rest breaks are an appropriate requirement for OGI camera operators because physical, mental, and eye fatigue are concerns with continuous field operation of OGI cameras. The EPA is proposing to update the requirement for rest breaks to once every 30 minutes, as one commenter[327] noted that this makes tracking breaks easier. The EPA does not believe that changing the continuous survey period from 20 minutes to 30 minutes will have a detrimental effect on an operator's ability to see leaks, and as such, is proposing to update the requirement to ease the burden on operators performing surveys. The EPA is not proposing a change in the length of the rest break. No comments were received on the specific length of the rest break. The EPA also notes that operators may perform tasks related to the survey, such as documentation, during rest breaks; the rest break is solely a break from actively imaging components.

The EPA proposed that OGI cameras must be capable of imaging methane emissions of 17 grams per hour(g/hr) and butane emissions of 18.5 g/hr at a viewing distance of 2 meters and a delta-T of 5 °C in an environment of calm wind conditions. Commenters stated that gases other than butane should be used for certification of cameras.[328] Additionally, some commenters stated that the emission rates in the camera certification should be the same as in NSPS OOOOa.[329] While the EPA does not agree that the camera certification should be the same as what is in NSPS OOOOa because we have learned more about the detection capabilities of OGI cameras since that time, we are proposing to change the butane requirement to a choice between propane or butane and noting that referencing subparts may provide specifications for other gases. The EPA is also clarifying that the initial certification testing, as well as the operating window development testing, can be performed by the owner or operator, the camera manufacturer, or a third party.

The EPA proposed that the response factors used when determining whether an OGI camera would be able to image the components in gaseous emissions would need to come from peer reviewed publications. Commenters requested that the EPA develop guidance on how to develop response factors and stated that the response factors should be able to be developed by manufacturers without the requirement for peer reviewed publication.[330] The EPA agrees with these comments, and as such, is proposing to remove the requirement for peer reviewed publications. Guidance for developing response factors is being provided as annex 1 to appendix K.

The EPA proposed that when a leak is found with OGI, the OGI camera operator must take a video clip of the leak. As requested by commenters, this requirement is being updated to allow a photograph of leaks as an option in lieu of video clips.[331] Additionally, as requested by a commenter, the EPA is proposing to allow the option for full videos of the surveys to be retained in lieu of video clips of leaks.[332]

The EPA is proposing to add a definition of monitoring survey, which means imaging equipment with an OGI camera at one site on one day. Changing site location or changing the day of imaging would constitute a new monitoring survey. This definition is needed to help clarify some of the requirements related to recordkeeping for monitoring surveys.

Finally, the EPA is also making a number of other clarifications and minor edits based on comments received during the November 2021 proposal.

C. Summary of Proposed Requirements

In this action, the EPA is proposing a protocol for the use of OGI as appendix K. As part of the development of appendix K, the EPA conducted an extensive literature review on the technology development as well as

[323] See Document ID Nos. EPA–HQ–OAR–2021–0317–0570, EPA–HQ–OAR–2021–0317–0599, EPA–HQ–OAR–2021–0317–0463, EPA–HQ–OAR–2021–0317–0608, EPA–HQ–OAR–2021–0317–0718, EPA–HQ–OAR–2021–0317–0782, EPA–HQ–OAR–2021–0317–0816, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0831, EPA–HQ–OAR–2021–0317–0916, and EPA–HQ–OAR–2021–0317–0954.

[324] See Document ID Nos. EPA–HQ–OAR–2021–0317–0561, EPA–HQ–OAR–2021–0317–0816, and EPA–HQ–OAR–2021–0317–0954.

[325] See Chapter 10 of the November 2021 TSD at Document ID No. EPA–HQ–OAR–2021–0317–0166.

[326] See Document ID Nos. EPA–HQ–OAR–2021–0317–0561, EPA–HQ–OAR–2021–0317–0599, EPA–HQ–OAR–2021–0317–0608, EPA–HQ–OAR–2021–0317–0718, EPA–HQ–OAR–2021–0317–0749, EPA–HQ–OAR–2021–0317–0750, EPA–HQ–OAR–2021–0317–0782, EPA–HQ–OAR–2021–0317–0793, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0814, EPA–HQ–OAR–2021–0317–0816, EPA–HQ–OAR–2021–0317–0954, and EPA–HQ–OAR–2021–0317–1373.

[327] See Document ID No. EPA–HQ–OAR–2021–0317–0561.

[328] See Document ID Nos. EPA–HQ–OAR–2021–0317–0599 and EPA–HQ–OAR–2021–0317–0808.

[329] See Document ID Nos. EPA–HQ–OAR–2021–0317–0782 and EPA–HQ–OAR–2021–0317–0808.

[330] See Document ID Nos. EPA–HQ–OAR–2021–0317–0808 and EPA–HQ–OAR–2021–0317–0831.

[331] See Document ID Nos. EPA–HQ–OAR–2021–0317–0463, EPA–HQ–OAR–2021–0317–0599, EPA–HQ–OAR–2021–0317–0808, EPA–HQ–OAR–2021–0317–0814 and EPA–HQ–OAR–2021–0317–1373.

[332] See Document ID No. EPA–HQ–OAR–2021–0317–0816.

observations on current application of OGI technology. Approximately 150 references identify the technology, applications, and limitations of OGI. The EPA also commissioned multiple laboratory studies and OGI technology evaluations. Additionally, on November 9 and 10, 2020, the EPA held a virtual stakeholder workshop to gather input on development of a protocol for the use of OGI. The information obtained from these efforts was used to develop the TSD for appendix K, which provides technical analyses, experimental results, and other supplemental information used to evaluate and develop standardized procedures for the use of OGI technology in monitoring for fugitive emissions of VOCs, HAP, and methane from industrial environments.[333]

The EPA notes that while this protocol is being proposed for use at onshore natural gas processing plants in this action at the proposed 40 CFR 60.5400b and 40 CFR 60.5400c, the applicability of the protocol is broader. The protocol is applicable to facilities when specified in a referencing subpart to help determine the presence and location of leaks; it is not currently applicable for use in direct emission rate measurements from sources. The protocol may be applied, when referenced, to surveys of process equipment using OGI cameras where the majority of compounds (>75 percent by weight) in the emissions streams have a response factor of at least 0.25 when compared to the response factor of propane. The OGI camera must also be capable of detecting (or producing a detectable image of) methane emissions of 17 g/hr and either butane emissions of 5.0 g/hr or propane emissions of 18 g/hr at a viewing distance of 2 meters and a delta-T of 5 °C in an environment of calm wind conditions around 1 meter per second or less. Verification that the OGI camera meets these criteria may be performed by the owner or operator, the camera manufacturer, or a third party. The supplies necessary for conducting the verification are described in section 6.2 of the proposed appendix.

Field conditions, such as the viewing distance to the component to be monitored, wind speed, ambient air temperature, and the background temperature, have the potential to impact the ability of the OGI camera operator to detect a leak. Because it is important that the OGI camera has been tested under the full range of expected field conditions in which the OGI camera will be used, an operating envelope must be established for field use of the OGI camera. Imaging must not be performed when the conditions are outside of the developed operating envelope. Operating envelopes are specific to each model of OGI camera and can be developed by the owner or operator, the camera manufacturer, or a third party. To develop the operating envelope, methane gas is released at a set mass rate and wind speed, viewing distance, and delta-T (the temperature differential of the background and the released gas) are all varied to determine the conditions under which a leak can be imaged. For purposes of developing the operating envelope, a leak is considered able to be imaged if three out of four observers can see the leak. Once the operating envelope is developed using methane, the testing is repeated with either butane or propane gas. The operating envelope for the OGI camera is the more restrictive operating envelope developed between the different test gases.

The operating envelope must be confirmed for all potential configurations that could impact the detection limit of the OGI camera. In response to the November 2021 proposal, several commenters suggested that the operating envelope determination requirements should be streamlined. For example, if a configuration is established and confirmed, another configuration that is inherently more sensitive should be allowed without additional testing. Commenters also requested a more defined and acceptable list of configurations be provided based on the technology's capabilities, not user preferences.[334] The EPA does not currently have enough data or empirical evidence to provide a complete list of possible configurations for all the available commercial OGI cameras (taking into account future possible configurations) or a definitive ranking of which configurations are more stringent than other. The EPA is requesting comment on this topic and seeking any empirical data that could be used to create such a defined ranking of configurations. Additionally, one commenter suggested that instead of having different operating envelopes for different situations and having to decide which envelope to use, the OGI camera operator should conduct a daily camera demonstration each day prior to imaging to determine the maximum distance at which the OGI camera operator should image for that day.[335] The EPA believes that this type of determination would be more difficult and costly than creating an operating envelope, as it would require OGI camera operators to have necessary gas supplies on hand and take time to do this determination daily, or potentially multiple times a day. Nevertheless, the EPA is requesting comment on this suggestion, as well as how such a demonstration could be used if conditions on the site change throughout the day, at what point would the changed conditions necessitate repeating the demonstration, and how changes in the background in different areas of the site (such as to affect the delta-T) would be factored into such a demonstration.

The EPA is proposing that each site would have a monitoring plan that describes the procedures for conducting a monitoring survey. One monitoring plan can be used for multiple sites, as long as the plan contains the relevant information for each site. The monitoring plan must contain procedures for a daily verification check, ensuring that the monitoring survey is performed only when conditions in the field are within the operating envelope, monitoring all the components regulated by the referencing subpart within the unit or area, viewing the components with the camera, operator rest breaks, documenting surveys, and quality assurance.

Delta-T is a crucial variable in determining whether it is possible to see a leak. Without an adequate delta-T, it will be difficult, or even impossible to see a leak, no matter how big the leak is. The EPA is proposing that the monitoring plan must describe how the operator will ensure an adequate delta-T is present in order to view potential gaseous emissions, *e.g.,* using a delta-T check function built into the features of the OGI camera or using a background temperature reading in the OGI camera field of view. In response to the November 2021 proposal, a commenter stated guidance should be added for operators who are using a background temperature reading in the OGI camera field of view.[336] The EPA is requesting comment on ways that an OGI camera operator can ensure an adequate delta-T exists during monitoring surveys for cameras that do not have a built-in delta-T check function.

The EPA is proposing that a component must be imaged from at least

[333] See Document ID No. EPA–HQ–OAR–2021–0317–0079.

[334] See Document ID Nos. EPA–HQ–OAR–2021–0317–0604 and EPA–HQ–OAR–2021–0317–0954.

[335] See Document ID No. EPA–HQ–OAR–2021–0317–0561.

[336] See Document ID No. EPA–HQ–OAR–2021–0317–0719.

two different angles, and the OGI camera operator must dwell on each angle for a minimum of 2 seconds per component in the field of view, where dwell time is defined as the time the scene is steady and in focus and the operator is actively viewing the scene. The operator may reduce the dwell time for complex scenes based on the monitoring area and number of components in the subsection as prescribed in Table 14–1 of the appendix; use of this table is only required when an operator wants to reduce the dwell time from the minimum 2 second per component dwell time. In response to the November 2021 proposal, commenters suggested that dwell time should be based on the scene, not on a per component basis. Additionally, commenters suggested further defining the scene as ''simple'' or ''complex'' with a greater dwell time for ''complex'' scenes.[337] The EPA is concerned with creating blanket dwell times for scenes, as scenes can vary in complexity within these categories, and an operator would need to look at scenes with more components longer than a scene with fewer components. Additionally, the EPA does not believe it is possible to describe every possible scene in order to create bins for ''simple'' and ''complex'' scenes that would be inclusive of all scenes an OGI camera operator might encounter in the field. However, the EPA is soliciting comment on how dwell time could be based on the scene while still accounting for the differences in the complexity of scenes or ways to create bins for ''simple'' and ''complex'' scenes. The EPA is also soliciting comment on ways to similarly achieve the goal of ensuring that OGI camera operators survey a scene for an adequate amount of time to ensure there are no leaks from any components in the field of view without specifying a dwell time.

Physical, mental, and eye fatigue are concerns with continuous field operation of OGI cameras. The EPA is proposing that OGI camera operators must take a rest break after surveying continuously for a period of 30 minutes. In response to the November 2021 proposal, commenters suggested that this was an unnecessary requirement. The EPA is aware that continuously surveying for long periods can lead to decreased detection of leaks. However, the EPA has heard anecdotally that this may have more to do with the number of hours the OGI camera operator has surveyed during the day, such that it is more appropriate to limit the hours of surveying per day than it is to mandate rest breaks at a set frequency. The EPA is seeking any empirical data on the topic of the necessity of rest breaks when conducting OGI surveys or the link between operator performance and length of survey period.

The EPA is proposing that the facility or company performing the OGI surveys must have a training plan which ensures and monitors the proficiency of the OGI camera operators. If the facility does not perform its own OGI monitoring, the facility must ensure that the training plan for the company performing the OGI surveys adheres to this requirement. The proposed appendix K prescribes a multi-faceted approach to training. Training includes classroom instruction (either online or at a physical location) both initially and biennially on the OGI camera and external devices, monitoring techniques, best practices, process knowledge, and other regulatory requirements related to leak detection that are relevant to the facility's OGI monitoring efforts. Prior to conducting monitoring surveys, camera operators must demonstrate proficiency with the OGI camera. The initial field training includes a minimum of 30 survey hours with OGI where trainees first observe the techniques and methods of a senior OGI camera operator and then eventually perform monitoring surveys independently with a senior OGI camera operator present to provide oversight. The trainee must then pass a final monitoring survey test of at least two hours. If there are 10 or more leaks identified by the senior OGI operator, the trainee must achieve less than 10 percent missed persistent leaks relative to the senior OGI camera operator to be considered authorized for independent survey execution. If there are less than 10 leaks identified by the senior OGI operator, the trainee must achieve zero missed persistent leaks relative to the senior OGI camera operator to be considered authorized for independent survey execution. If the trainee doesn't pass the monitoring survey test, the senior OGI camera operator must discuss the reasons for the failure with the trainee and provide instruction/correction on improving the trainee's performance, following which the trainee may repeat the final test.

The EPA is proposing that performance audits for all OGI camera operators must occur on a quarterly basis and can be conducted either by comparative monitoring or video review by a senior OGI camera operator. If the senior OGI camera operator finds that the survey techniques during the video review do not match those described in the monitoring plan, then the camera operator being audited will need to be retrained. Additionally, if there are 10 or more leaks identified by the senior OGI operator, the camera operator being audited must achieve less than 10 percent missed persistent leaks relative to the senior OGI camera operator. If there are less than 10 leaks identified by the senior OGI operator, the camera operator being audited must achieve zero missed persistent leaks relative to the senior OGI camera operator. Retraining consists of a discussion of the reasons for the failure with the OGI operator being audited and techniques to improve performance; a minimum of 16 survey training hours; and a final monitoring survey test. If an OGI operator requires retraining in two consecutive quarterly audits, the OGI operator must repeat the initial training requirements. In response to the November 2021 proposal, commenters stated that there should be no performance audit requirements for senior OGI camera operators because senior OGI camera operators are responsible for training and auditing other OGI camera operators. The EPA believes that it is important to verify the performance of all OGI camera operators, even the most experienced operators, on an ongoing basis. Nevertheless, the EPA is requesting comment on whether there should be a reduced performance audit frequency for certain OGI camera operators, and if so, who should qualify for a reduced frequency, what the reduced frequency should be, and the basis for the reduced frequency.

Previous experience with OGI camera operation can be substituted for some of the initial training requirements. OGI camera operators with previous classroom training (either at a physical location or online) that covers the majority of the elements required by the initial classroom training required in appendix K prior to the finalization of appendix K do not need to complete the initial classroom training, but if the date of certification is more than 2 years before the publication date of the final rule, the biennial classroom training must be completed in lieu of the initial classroom training. OGI camera operators who have 40 hours of experience over the 12 calendar months prior to the date of publication of the final rule may substitute the retraining requirements, including the final monitoring survey test, for the initial field training requirements.

Recordkeeping is an important compliance assurance measure. The proposed appendix K requires records

[337] See Document ID Nos. EPA–HQ–OAR–2021–0317–0561, EPA–HQ–OAR–2021–0317–0604, EPA–HQ–OAR–2021–0317–0816, and EPA–HQ–OAR–2021–0317–0954.

to be retained in hard copy or electronic form. Records include the site monitoring plan, operating envelope limitations, data supporting the initial OGI camera performance verification and development of the operating envelope, the training plan for OGI camera operators, OGI camera operator training and auditing records, records necessary to verify senior OGI camera operator status, monitoring survey records, quality assurance verification videos for each operator, and maintenance and calibration records. Some of the records required by the proposed appendix K are not required to be kept onsite as long as the owner or operator can easily access these records and can make the records available for review if requested by the Administrator.

VII. Impacts of This Proposed Rule

A. What are the air impacts?

The EPA projected that, from 2023 to 2035, relative to the baseline, the proposed NSPS OOOOb and EG OOOOc will reduce about 36 million short tons of methane emissions (810 million tons CO_2 Eq.), 9.7 million short tons of VOC emissions, and 390 thousand short tons of HAP emission from facilities that are potentially affected by this proposal. The EPA projected regulatory impacts beginning in 2023 as that year represents the first full year of implementation of the proposed NSPS OOOOb. The EPA assumes that emissions impacts of the proposed EG OOOOc will begin in 2026. The EPA projected impacts through 2035 to illustrate the accumulating effects of this rule over a longer period. The EPA did not estimate impacts after 2035 for reasons including limited information, as explained in the RIA, though the EPA is soliciting comment on whether information exists to better characterize the likely effects beyond 2035.

As noted in section I of this preamble, the updated analysis not only incorporates the new provisions put forth in the supplemental proposal (in addition to the elements of the November 2021 proposal that are unchanged), but also includes key updates to assumptions and methodologies that impact both the baseline and policy scenarios. Accordingly, these estimates of air impacts are not directly comparable to corresponding estimates presented in the November 2021 proposal.

B. What are the energy impacts?

The energy impacts described in this section are those energy requirements associated with the operation of emission control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section in VIII.D of this preamble. There will likely be minimal change in emissions control energy requirements resulting from this rule. Additionally, this proposed action continues to encourage the use of emission controls that recover hydrocarbon products that can be used on-site as fuel or reprocessed within the production process for sale.

C. What are the compliance costs?

The equivalent annualized value, or EAV, of the regulatory compliance cost associated with the proposed NSPS OOOOb and EG OOOOc over the 2023 to 2035 period was estimated to be $1.4 billion per year using a 3-percent discount rate and $1.4 billion using a 7-percent discount rate. The corresponding estimates of the present value (PV) of compliance costs were $14 billion (in 2019 dollars) using a 3-percent discount rate and $12 billion using a 7-percent discount rate. These estimates include the producer revenues associated with the projected increase in the recovery of saleable natural gas, using the 2022 Annual Energy Outlook (AEO) projection of natural gas prices to estimate the value of the change in the recovered gas at the wellhead projected to result from the proposed action. Estimates of the value of the recovered product have been included in previous regulatory analyses as offsetting compliance costs and are appropriate to include when assessing the societal cost of a regulation. If the recovery of saleable natural gas is not accounted for, the EAV of the regulatory compliance costs of the proposed rule over the 2023 to 2035 period were estimated to be $1.8 billion per year using a 3-percent discount rate and $1.8 billion per year using a 7-percent discount rate. The PV of these costs were estimated to be $19 billion using a 3-percent discount rate and $15 billion using a 7-percent discount rate.

D. What are the economic and employment impacts?

The EPA conducted an economic impact and distributional analysis for this proposal, as detailed in section 4 of the RIA for this supplemental proposal. To provide a partial measure of the economic consequences of the proposed NSPS OOOOb and EG OOOOc, the EPA developed a pair of single-market, static partial-equilibrium analyses of national crude oil and natural gas markets. We implemented the pair of single-market analyses instead of a coupled market or general equilibrium approach to provide broad insights into potential national-level market impacts while providing maximum analytical transparency. We estimated the price and quantity impacts of the proposed NSPS OOOOb and EG OOOOc on crude oil and natural gas markets for a subset of years within the time horizon analyzed in the RIA. The models are parameterized using production and price data from the U.S. Energy Information Administration and supply and demand elasticity estimates from the economics literature.

The RIA projects that regulatory costs are at their highest in 2026, the first year the requirements of both the proposed NSPS OOOOb and EG OOOOc are assumed to be in effect and will represent the year with the largest market impacts based upon the partial equilibrium modeling. We estimated that the proposed rule could result in a maximum decrease in annual natural gas production of about 358 million Mcf in 2026 (or about 1.00 percent of natural gas production) with a maximum price increase of $0.07 per Mcf (or about 2.35 percent). We estimated the maximum annual reduction in crude oil production would be about 21 million barrels (or about 0.52 percent of crude oil production) with a maximum price increase of about $0.10 per barrel (or less than 0.16 percent).

Before 2026, the modeled market impacts are much smaller than the 2026 impacts as only the incremental requirements under the proposed NSPS OOOOb are assumed to be in effect. As regulatory costs are projected to decline after 2026, the modelled market impacts for years after 2026 are smaller than the peaks estimated for 2026. Please see section 4.1 of the RIA for more detail on the formulation and implementation of the model as well as a discussion of several important caveats and limitations associated with the approach.

As discussed in the RIA for this proposal, employment impacts of environmental regulations are generally composed of a mix of potential declines and gains in different areas of the economy over time. Regulatory employment impacts can vary across occupations, regions, and industries; by labor and product demand and supply elasticities; and in response to other labor market conditions. Isolating such impacts is a challenge, as they are difficult to disentangle from employment impacts caused by a wide variety of ongoing, concurrent economic changes.

The oil and natural gas industry directly employs approximately 140,000 people in oil and natural gas extraction, a figure which varies with market prices and technological change and employs a large number of workers in related sectors that provide materials and services.[338] As indicated above, the proposed NSPS OOOOb and EG OOOOc are projected to cause small changes in oil and natural gas production and prices. As a result, demand for labor employed in oil and natural gas-related activities and associated industries might experience adjustments as there may be increases in compliance-related labor requirements as well as changes in employment due to quantity effects in directly regulated sectors and sectors that consume oil and natural gas products.

E. What are the benefits of the proposed standards?

To satisfy the requirement of E.O. 12866 and to inform the public, the EPA estimated the climate and health benefits due to the emissions reductions projected under the proposed NSPS OOOOb and EG OOOOc. The EPA expects climate and health benefits due to the emissions reductions projected under the proposed NSPS OOOOb and EG OOOOc. The EPA estimated the climate benefits of CH_4 emission reductions expected from this proposed rule using the SC–CH_4 estimates presented in the ''Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under E.O. 13990 (IWG 2021)'' published in February 2021 by the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG). The SC–CH_4 is the monetary value of the net harm to society associated with a marginal increase in emissions in a given year, or the benefit of avoiding that increase. In principle, SC–CH_4 includes the value of all climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC–CH_4 therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton and is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CH_4 emissions.

The interim estimates of the social cost of methane and other greenhouse gases (collectively referred to as the social cost of greenhouse gases (SC–GHG)) presented in the February 2021 Technical Support Document (TSD) (IWG 2021) were developed over many years, using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. As a member of the IWG involved in the development of the February 2021 TSD, the EPA agrees that the interim SC–GHG estimates continue to represent at this time the most appropriate estimate of the SC–GHG until revised estimates have been developed reflecting the latest, peer-reviewed science. However, while the IWG's SC–GHG work under E.O. 13990 continues, the RIA accompanying this proposal the EPA presents a sensitivity analysis of the monetized climate benefits using a set of SC–CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine (2017).

We invite the public to comment on both the sensitivity analysis of the monetized climate benefits and the accompanying external review draft technical report that the EPA has prepared that explains the methodology underlying the newer set of SC–CH_4 estimates. This report is also included as supporting material for the RIA in the docket.[339] However, we emphasize that the monetized benefits analysis is entirely distinct from the statutory BSER determinations proposed herein and is presented solely for the purposes of complying with E.O. 12866. As discussed in more detail in the November 2021 proposal and earlier in this notice, the EPA weighed the relevant statutory factors to determine the appropriate proposed standards and did not rely on the monetized benefits analysis for purposes of determining the standards. E.O. 12866 separately requires the EPA to perform a benefit-cost analysis, including monetizing costs and benefits where practicable, and the EPA has conducted such an analysis. The monetized climate benefits calculated using the SC–CH_4 are included in the benefit-cost analysis, and thus, as is generally the case with any analytical methods, data, or results associated with RIAs, the EPA welcomes the opportunity to continually improve its understanding through public input on these estimates.

The EPA estimated the PV of the climate benefits over the 2023 to 2035 period to be $48 billion at a 3-percent discount rate. The EAV of these benefits is estimated to be $4.5 billion per year at a 3-percent discount rate. These values represent only a partial accounting of climate impacts from methane emissions and do not account for health effects of ozone exposure from the increase in methane emissions.

Under the proposed NSPS OOOOb and EG OOOOc, the EPA expects that VOC emission reductions will improve air quality and are likely to improve health and welfare associated with exposure to ozone, $PM_{2.5}$, and HAP. Calculating ozone impacts from VOC emissions changes requires information about the spatial patterns in those emissions changes. In addition, the ozone health effects from the proposed rule will depend on the relative proximity of expected VOC and ozone changes to population. In this analysis, we have not characterized VOC emissions changes at a finer spatial resolution than the national total. In light of these uncertainties, we present an illustrative screening analysis in Appendix C of the RIA based on modeled oil and natural gas VOC contributions to ozone concentrations as they occurred in 2017 and do not include the results of this analysis in the estimate of benefits and net benefits projected from this proposal.

VIII. Statutory and Executive Order Reviews

Additional information about these statutes and EOs 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 proposed action is an economically significant regulatory action that was submitted to the OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, ''Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review'', is available in the docket and describes in detail the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates.

B. Paperwork Reduction Act (PRA)

The information collection activities in the proposed amendments for 40 CFR part 60, subparts OOOOb and OOOOc,

[338] Employment figure drawn from the Bureau of Labor Statistics Current Employment Statistics for NAICS code 211.

[339] For more information about the development of these estimates, see *www.epa.gov/environmental-economics/scghg.*

have been submitted for approval to the OMB under the PRA. The ICR document that the EPA prepared has been assigned OMB Control No. 2060–0721 and EPA ICR number 2523.05. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. As noted in section IV.N of this supplemental preamble, draft versions of the proposed templates for the semiannual and annual reports for these subparts are included in the docket for this action,[340] and the EPA specifically requests comment on the content, layout, and overall design of the templates.

40 CFR Part 60, Subpart OOOOb

This ICR reflects the EPA's proposed NSPS OOOOb for a wide range of emissions sources in the Crude Oil and Natural Gas source category. The information collected will be used by the EPA and delegated state and local agencies to determine the compliance status of affected facilities subject to the rule.

Respondents/affected entities: Oil and natural gas operators and owners; approved third-party notifiers.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 1,849.

Frequency of response: Varies depending on affected facility.[341]

Total estimated burden: 883,625 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $58,535,262($2019) (per year), which includes $12,182,846 in capital costs.

40 CFR Part 60, subpart OOOOc

This rule does not directly impose specific requirements on oil and natural gas facilities located in states or areas of Indian country. The rule also does not impose specific requirements on tribal governments that have affected facilities located in their area of Indian country. This rule does impose specific requirements on state governments with affected oil and natural gas facilities. The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a plan to limit GHG emissions from existing sources in the oil and natural gas sector. These recordkeeping and reporting requirements are specifically authorized by CAA section 114 (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to Agency policies set forth in 40 CFR part 2, subpart B.

The annual burden for this collection of information for the states (averaged over the first 3 years following promulgation) is estimated to range from 55,467 to 69,333 hours at a total annual labor cost of between $7 to $8.8 million. The annual burden for the Federal government associated with the state collection of information (averaged over the first 3 years following promulgation) is estimated to be 22,520 hours at a total annual labor cost of $1,399,930. The annual burden for industry (averaged over the first 3 years following promulgation) is estimated to be 2.2 million hours at a total annual labor cost of $166 million. We realize, however, that some facilities may not incur these costs within the first 3 years and may incur them during the fourth or fifth year instead. Therefore, this ICR presents a conservatively high burden estimate for the initial 3 years following promulgation of the proposed emission guidelines. Burden is defined at 5 CFR 1320.3(b).

Respondents/affected entities: States with one or more designated facilities covered under subpart OOOOc.

Respondent's obligation to respond: Mandatory.

Estimated number of respondents: 50.

Frequency of response: Once.

Total estimated burden: 69,333 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $8,822,020 (per year), which includes $36,750 in capital 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. Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under 30-day Review—Open for Public Comments'' or by using the search function. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than January 5, 2023.

C. Regulatory Flexibility Act (RFA)

Pursuant to section 603 of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) that examined the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. The complete IRFA is available for review in the RIA (see Section 4.3) and the EPA is soliciting comment on the presentation of its analysis of the impacts on small entities, particularly if there is value in presenting more granular information beyond a focus on entities above and below the SBA size classifications.

As required by section 609(b) of the RFA, the EPA also convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives that potentially would be subject to the rule's requirements. The SBAR Panel evaluated the assembled materials and small-entity comments on issues related to elements of an IRFA. A copy of the full SBAR Panel Report is available in the rulemaking docket.

As required by section 604 of the RFA, the EPA will prepare a final regulatory flexibility analysis (FRFA) for this action as part of the final rule. The FRFA will address the issues raised by public comments on the IRFA.

D. Unfunded Mandates Reform Act (UMRA)

The NSPS contains a federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of $100 million or more for state, tribal, and local governments, in the aggregate, or the private sector in any one year. Accordingly, the EPA has prepared under section 202 of the UMRA a written statement of the benefit-cost analysis, which can be found in Section VII of this preamble, and in Chapter 1 of the RIA.

Consistent with section 205, the EPA has identified and considered a reasonable number of regulatory alternatives. These alternatives are described in Section IV of this preamble.

The EG is proposed under CAA section 111(d) and does not impose any direct compliance requirements on designated facilities, apart from the

[340] See Part_60_Subpart_OOOOb_60.5420b(b)_Annual_Report.xlsm and Part_60_Subpart_OOOOb_60.5422b(b)_Semiannual_Report.xlsx, available in the docket for this action.

[341] The specific frequency for each information collection activity within this request is shown in Tables 1a through 1d of the Supporting Statement in the public docket.

requirement for states to develop state plans. As explained in section XIV.G. of the November 2021 proposal [342] and section V of this supplemental proposal, the EG also does not impose specific requirements on tribal governments that have designated facilities located in their area of Indian country. The burden for states to develop state plans following promulgation of the rule is estimated to be below $100 million in any one year. Thus, the EG is not subject to the requirements of section 203 or section 205 of the UMRA.

The NSPS and EG are also not subject to the requirements of section 203 of UMRA because, as described in 2 U.S.C. 1531–38, they contain no regulatory requirements that might significantly or uniquely affect small governments. Specifically, for the EG the state governments to which rule requirements apply are not considered small governments. In light of the interest among governmental entities, the EPA conducted pre-proposal outreach with national organizations representing states and tribal governmental entities while formulating the proposed rule as discussed in section VII of the November 2021 proposal.[343] The EPA considered the stakeholders' experiences and lessons learned to help inform how to better structure this proposal and consider ongoing challenges that will require continued collaboration with stakeholders. With this proposal, the EPA seeks further input from states and tribes. For public input to be considered during the formal rulemaking, please submit comments on this proposed action to the formal regulatory docket at EPA Docket ID No. EPA–HQ–OAR–2021–0317 so that the EPA may consider those comments during the development of the final rule.

E. Executive Order 13132: Federalism

Under Executive Order 13132, the EPA may not issue an action that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal Government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or the EPA consults with state and local officials early in the process of developing the proposed action.

The proposed NSPS OOOOb and proposed EG OOOOc do not have federalism implications. These actions will not have substantial direct effects on the states as defined in the Executive Order, on the relationship between the Federal 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 has tribal implications. However, it will neither impose substantial direct compliance costs on Federally recognized Tribal governments, nor preempt Tribal law, and does not 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, as specified in E.O. 13175. See 65 FR 67249 (November 9, 2000). As stated in the November 2021 proposal, the EPA found that 112 unique tribal lands are located within 50 miles of an affected oil and natural gas source, and 32 tribes have one or more oil or natural gas sources on their lands.[344] The majority of the designated facilities impacted by proposed NSPS and EG on Tribal lands are owned by private entities, and tribes will not be directly impacted by the compliance costs associated with this rulemaking. There would only be tribal implications associated with this rulemaking in the case where a unit is owned by a Tribal government or in the case of the NSPS, a Tribal government is given delegated authority to enforce the rulemaking. Tribes are not required to develop plans to implement the EG under CAA section 111(d) for designated existing sources. The EPA notes that this supplemental proposal does not directly impose specific requirements on designated facilities, including those located in Indian country. Before developing any standards for sources on Tribal land, the EPA would consult with leaders from affected tribes.

After the November 2021 proposal, the EPA held consultation with the Mandan, Hidatsa, and Arikara Nation (January 24, 2022), the Northern Arapaho Tribe (January 24, 2022), and the Eastern Shoshone Tribe (January 25, 2022).[345] Consistent with previous actions affecting the Crude Oil and Natural Gas source category, the EPA understands there is continued significant tribal interest because of the growth of the oil and natural gas production in Indian country. In accordance with the EPA Policy on Consultation and Coordination with Indian Tribes, the EPA will continue to engage in consultation with tribal officials during the development of this supplemental proposal.

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 an economically significant regulatory action as defined by E.O. 12866, and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the Agency has evaluated the environmental health and welfare effects of climate change on children. GHGs, including methane, contribute to climate change and are emitted in significant quantities by the oil and gas industry. The EPA believes that the GHG emission reductions resulting from implementation of these proposed standards and guidelines, if finalized will further improve children's health. The assessment literature cited in the EPA's 2009 Endangerment Findings concluded that certain populations and life stages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects (74 FR 66524). The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience (*e.g.,* the 2016 Climate and Health Assessment).[346] These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households. More

[342] See 86 FR 63256 (November 15, 2021).

[343] See 86 FR 63145 (November 15, 2021).

[344] 86 FR 63143 (November 15, 2021).

[345] See memorandums located at Docket ID No. EPA–HQ–OAR–2021–0317.

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

detailed information on the impacts of climate change to human health and welfare is provided in sections III and VI of the November 2021 proposal [347] and section VII of this preamble.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action, which is a significant regulatory action under Executive Order 12866, has a significant adverse effect on the supply, distribution or use of energy. The documentation for this decision is contained in the *Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* prepared for the November 2021 proposal and the *Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* for this action [348]

I. National Technology Transfer and Advancement Act (NTTAA)

This proposed action for NSPS OOOOb and EG OOOOc involves technical standards. Therefore, the EPA conducted searches for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 3A, 3B, 3C, 4, 6, 10, 15, 16, 16A, 18, 21, 22, and 25A of 40 CFR part 60, appendix A. No applicable voluntary consensus standards were identified for EPA Methods 1A, 2A, 2D, 21, and 22 and none were brought to its attention in comments. All potential standards were reviewed to determine the practicality of the voluntary consensus standards (VCS) for this rule. Two VCS were identified as an acceptable alternative to EPA test methods for the purpose of this proposed rule. First, ANSI/ASME PTC 19–10–1981, Flue and Exhaust Gas Analyses (Part 10) (manual portions only and not the instrumental portion) was identified to be used in lieu of EPA Methods 3B, 6, 6A, 6B, 15A and 16A. This standard includes manual and instrumental methods of analysis for carbon dioxide, carbon monoxide, hydrogen sulfide, nitrogen oxides, oxygen, and sulfur dioxide. Second, ASTM D6420–99 (2010), ''Test Method for Determination of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry'' is an acceptable alternative to EPA Method 18 with the following caveats, only use when the target compounds are all known and the target compounds are all listed in ASTM D6420 as measurable. ASTM D6420 should never be specified as a total VOC Method. (ASTM D6420–99 (2010) is not incorporated by reference in 40 CFR part 60.) The search identified 19 VCS that were potentially applicable for this proposed rule in lieu of EPA reference methods. However, these have been determined to not be practical due to lack of equivalency, documentation, validation of data and other important technical and policy considerations. For additional information, please see the September 10, 2021, memo titled, ''Voluntary Consensus Standard Results for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review.'' [349] In this document, the EPA is proposing to include in a final rule regulatory text for 40 CFR part 60, subpart OOOOb and OOOOc that includes incorporation by reference. In accordance with requirements of 1 CFR part 51, the EPA is proposing to incorporate the following ten standards by reference.

- ASTM D86–96, Distillation of Petroleum Products (Approved April 10, 1996) covers the distillation of natural gasolines, motor gasolines, aviation gasolines, aviation turbine fuels, special boiling point spirits, naphthas, white spirit, kerosenes, gas oils, distillate fuel oils, and similar petroleum products, utilizing either manual or automated equipment.
- ASTM D1945–03 (Reapproved 2010), Standard Test Method for Analysis of Natural Gas by Gas Chromatography covers the determination of the chemical composition of natural gases and similar gaseous mixtures within a certain range of composition. This test method may be abbreviated for the analysis of lean natural gases containing negligible amounts of hexanes and higher hydrocarbons, or for the determination of one or more components.
- ASTM D3588–98 (Reapproved 2003), Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuel covers procedures for calculating heating value, relative density, and compressibility factor at base conditions for natural gas mixtures from compositional analysis. It applies to all common types of utility gaseous fuels.
- ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion covers the determination of the heating value of natural gases and similar gaseous mixtures within a certain range of composition.
- ASTM D6522–00 (Reapproved December 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas-Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers covers the determination of nitrogen oxides, carbon monoxide, and oxygen concentrations in controlled and uncontrolled emissions from natural gas-fired reciprocating engines, combustion turbines, boilers, and process heaters.
- ASTM E168–92, General Techniques of Infrared Quantitative Analysis covers the techniques most often used in infrared quantitative analysis. Practices associated with the collection and analysis of data on a computer are included as well as practices that do not use a computer.
- ASTM E169–93, General Techniques of Ultraviolet Quantitative Analysis (Approved May 15, 1993) provide general information on the techniques most often used in ultraviolet and visible quantitative analysis. The purpose is to render unnecessary the repetition of these descriptions of techniques in individual methods for quantitative analysis.
- ASTM E260–96, General Gas Chromatography Procedures (Approved April 10, 1996) is a general guide to the application of gas chromatography with packed columns for the separation and analysis of vaporizable or gaseous organic and inorganic mixtures and as a reference for the writing and reporting of gas chromatography methods.
- ASME/ANSI PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus] (Issued August 31, 1981) covers measuring the oxygen or carbon dioxide content of the exhaust gas.
- EPA–600/R–12/531, EPA Traceability Protocol for Assay and Certification of Gaseous Calibration

[347] See 86 FR 63124 and 86 FR 63139 (November 15, 2021).

[348] See Document ID No. EPA–HQ–OAR–2021–0317–0173.

[349] See Document ID No. EPA–HQ–OAR–2021–0317–0072.

Standards (Issued May 2012) is mandatory for certifying the calibration gases being used for the calibration and audit of ambient air quality analyzers and continuous emission monitors that are required by numerous parts of the CFR.

The EPA determined that the ASTM and ASME/ANSI standards, notwithstanding the age of the standards, are reasonably available because it they are available for purchase from the following addresses: ASTM International (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959; or ProQuest, 300 North Zeeb Road, Ann Arbor, MI 48106 and the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990. The EPA determined that the EPA standard is reasonably available because it is publicly available through the EPA's website: *https://nepis.epa.gov/Adobe/PDF/P100EKJR.pdf.*

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially applicable VCS and to explain why such standards should be used in this regulation.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

This action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations, and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629; February 16, 1994). The documentation for this assessment is contained in section 4 of the *Regulatory Impact Analysis for the Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* prepared for the November 2021 proposal and in section 4 of the *Regulatory Impact Analysis of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review* prepared for this action.[350]

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference; Reporting and recordkeeping requirements.

Michael S. Regan,

Administrator.

[FR Doc. 2022–24675 Filed 12–5–22; 8:45 am]

BILLING CODE 6560–50–P

[350] See Document ID No. EPA–HQ–OAR–2021–0317–0173.

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Part III

Department of Energy

10 CFR Part 431
Energy Conservation Program: Energy Conservation Standards for Circulator Pumps; Proposed Rule

DEPARTMENT OF ENERGY

10 CFR Part 431

[EERE–2016–BT–STD–0004]

RIN 1904–AD61

Energy Conservation Program: Energy Conservation Standards for Circulator Pumps

AGENCY: Office of Energy Efficiency and Renewable Energy, Department of Energy.

ACTION: Notice of proposed rulemaking and announcement of public meeting.

SUMMARY: The Energy Policy and Conservation Act, as amended (''EPCA''), prescribes energy conservation standards for various consumer products and certain commercial and industrial equipment, including circulator pumps. In this notice of proposed rulemaking (''NOPR''), DOE proposes energy conservation standards for circulator pumps, and also announces a public meeting to receive comment on these proposed standards and associated analyses and results.

DATES:

Comments: DOE will accept comments, data, and information regarding this NOPR no later than February 6, 2023.

Meeting: DOE will hold a public meeting via webinar on Thursday, January 19, 2023, from 1:00 p.m. to 4:00 p.m., in Washington, DC.

Comments regarding the likely competitive impact of the proposed standard should be sent to the Department of Justice contact listed in the **ADDRESSES** section on or before February 6, 2023.

Interested persons are encouraged to submit comments using the Federal eRulemaking Portal at *www.regulations.gov,* under docket number EERE–2016–BT–STD–0004. Follow the instructions for submitting comments. Alternatively, interested persons may submit comments, identified by docket number EERE–EERE–2016–BT–STD–0004, by any of the following methods:

Email: Circpumps2016std0004@ee.doe.gov. Include the docket number EERE–2016–BT–STD–0004 in the subject line of the message.

Postal Mail: Appliance and Equipment Standards Program, U.S. Department of Energy, Building Technologies Office, Mailstop EE–5B, 1000 Independence Avenue SW, Washington, DC 20585–0121. Telephone: (202) 287–1445. If possible, please submit all items on a compact disc (''CD''), in which case it is not necessary to include printed copies.

Hand Delivery/Courier: Appliance and Equipment Standards Program, U.S. Department of Energy, Building Technologies Office, 950 L'Enfant Plaza SW, 6th Floor, Washington, DC 20024. Telephone: (202) 287–1445. If possible, please submit all items on a CD, in which case it is not necessary to include printed copies.

No telefacsimiles (''faxes'') will be accepted. For detailed instructions on submitting comments and additional information on this process, see section VII of this document.

Docket: The docket for this activity, which includes **Federal Register** notices, comments, and other supporting documents/materials, is available for review at *www.regulations.gov.* All documents in the docket are listed in the *www.regulations.gov* index. However, not all documents listed in the index may be publicly available, such as information that is exempt from public disclosure.

The docket web page can be found at *www.regulations.gov/docket/EERE–2016–BT–STD–0004/document.* The docket web page contains instructions on how to access all documents, including public comments, in the docket. See section VII of this document for information on how to submit comments through *www.regulations.gov.*

EPCA requires the Attorney General to provide DOE a written determination of whether the proposed standard is likely to lessen competition. The U.S. Department of Justice Antitrust Division invites input from market participants and other interested persons with views on the likely competitive impact of the proposed standard. Interested persons may contact the Division at *energy.standards@usdoj.gov* on or before the date specified in the **DATES** section. Please indicate in the ''Subject'' line of your email the title and Docket Number of this proposed rulemaking.

FOR FURTHER INFORMATION CONTACT:

Mr. Jeremy Dommu, U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, Building Technologies Office, EE–5B, 1000 Independence Avenue SW, Washington, DC 20585–0121. Telephone: (202) 586–9870. Email: *ApplianceStandardsQuestions@ee.doe.gov.*

Mr. Nolan Brickwood, U.S. Department of Energy, Office of the General Counsel, GC–33, 1000 Independence Avenue SW, Washington, DC 20585–0121. Telephone: (202) 586–2555. Email: *Nolan.Brickwood@hq.doe.gov.*

For further information on how to submit a comment, review other public comments and the docket, or participate in the public meeting, contact the Appliance and Equipment Standards Program staff at (202) 287–1445 or by email: *ApplianceStandardsQuestions@ee.doe.gov.*

SUPPLEMENTARY INFORMATION:

Table of Contents

I. Synopsis of the Proposed Rule

Title III, Part C [1] of EPCA,[2] established the Energy Conservation Program for Certain Industrial Equipment. (42 U.S.C. 6311–6317) Such equipment includes pumps. Circulator pumps, which are the subject of this proposed rulemaking, are a category of pumps.

Pursuant to EPCA, any new or amended energy conservation standard must be designed to achieve the maximum improvement in energy efficiency that DOE determines is technologically feasible and economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(A)) Furthermore, the new or amended standard must result in a significant conservation of energy. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(B)) EPCA also provides that not later than 6 years after issuance of any final rule establishing or amending a standard, DOE must publish either a notice of determination that standards for the product do not need to be amended, or a notice of proposed rulemaking including new proposed energy conservation standards (proceeding to a final rule, as appropriate). (42 U.S.C. 6316(a); 42 U.S.C. 6295(m))

In accordance with these and other statutory provisions discussed in this document, DOE proposes energy conservation standards for circulator pumps. The proposed standards, which are expressed in terms of a maximum circulator energy index (''CEI''), are shown in Table I.1. CEI represents the weighted average electric input power to the driver over a specified load profile, normalized with respect to a circulator pump serving the same hydraulic load that has a specified minimum performance level.[3] These proposed standards, if adopted, would apply to all circulator pumps listed in Table I.1 manufactured in, or imported into, the United States starting on the date 2 years after the publication of the final rule for this proposed rulemaking.

TABLE I.1—PROPOSED ENERGY CONSERVATION STANDARDS FOR CIRCULATOR PUMPS

Equipment class	Maximum CEI
(All Circulator Pumps)	1.00

[1] For editorial reasons, upon codification in the U.S. Code, Part C was redesignated Part A–1.

[2] All references to EPCA in this document refer to the statute as amended through the Energy Act of 2020, Public Law 116–260 (Dec. 27, 2020), which reflect the last statutory amendments that impact Parts A and A–1 of EPCA.

[3] The performance of a comparable pump that has a specified minimum performance level is referred to as the circulator energy rating (''CER'').

As stated in section III.C.a of this document, the proposed standards apply to circulator pumps when operated using the least consumptive control variety with which they are equipped.

CEI is defined as shown in equation (1), and consistent[4] with section 41.5.3.2 of HI 41.5–2022, ''Hydraulic Institute Program Guideline for Circulator Pump Energy Rating Program.''[5] 87 FR 57264.

$$CEI = \left[\frac{\text{CER}}{CER_{STD}}\right] \quad \textbf{(1)}$$

Where:

CEI = the circulator energy index (dimensionless);
CER = circulator energy rating (hp); and
CER_{STD} = for a circulator pump that is minimally compliant with DOE's energy conservation standards with the same hydraulic horsepower as the tested pump, as determined in accordance with the specifications at paragraph (i) of § 431.465.

The specific formulation for CER, in turn, varies according to circulator pump control variety, but in all cases is a function of measured pump input power when operated under certain conditions, as described in the September 2022 TP Final Rule.

Relatedly, CER_{STD} represents CER for a circulator pump that is minimally compliant with DOE's energy conservation standards with the same hydraulic horsepower as the tested pump, as determined in accordance with the specifications at paragraph (i) of § 431.465. 87 FR 57264.

A. Benefits and Costs to Consumers

Table I.2 presents DOE's evaluation of the economic impacts of the proposed standards on consumers of circulator pumps, as measured by the average life-cycle cost (''LCC'') savings and the simple payback period (''PBP'').[6] The average LCC savings are positive, and the PBP is less than the average lifetime of circulator pumps, which is estimated to be approximately 10.5 years (*see* section IV.F.6 of this document).

TABLE I.2—IMPACTS OF PROPOSED ENERGY CONSERVATION STANDARDS ON CONSUMERS OF CIRCULATOR PUMPS

Equipment class	Average LCC savings (2021$)	Simple payback period (years)
All Circulator Pumps	103.2	4.2

DOE's analysis of the impacts of the proposed standards on consumers is described in section IV.F of this document.

B. Impact on Manufacturers

The industry net present value (''INPV'') is the sum of the discounted cash flows to the industry from the base year through the end of the analysis period (2022–2055). Using a real discount rate of 9.6 percent, DOE estimates that the INPV for manufacturers of circulator pumps in the case without standards is $325.9 million in 2021$. Under the proposed standards, the change in INPV is estimated to range from −19.7 percent to 6.6 percent, which is approximately equivalent to a decrease of $64.3 million to an increase of 21.4 million. In order to bring products into compliance with standards, it is estimated that the industry would incur total conversion costs of $77.0 million.

DOE's analysis of the impacts of the proposed standards on manufacturers is described in section IV.J of this document. The analytic results of the manufacturer impact analysis (''MIA'') are presented in section V.B.2 of this document.

C. National Benefits and Costs[7]

DOE's analyses indicate that the proposed energy conservation standards for circulator pumps would save a significant amount of energy. Relative to the case without standards, the lifetime energy savings for circulator pumps purchased in the 30-year period that begins in the anticipated year of compliance with the standards (2026–2055) amount to 0.45 quadrillion British thermal units (''Btu''), or quads.[8] This represents a savings of 34 percent relative to the energy use of these products in the case without standards (referred to as the ''no-new-standards case'').

The cumulative net present value (''NPV'') of total consumer benefits of the proposed standards for circulator pumps ranges from $0.73 billion (at a 7-percent discount rate) to $1.77 billion (at a 3-percent discount rate). This NPV expresses the estimated total value of future operating-cost savings minus the estimated increased equipment and installation costs for circulator pumps purchased in 2026–2055.

In addition, the proposed standards for circulator pumps are projected to yield significant environmental benefits. DOE estimates that the proposed standards would result in cumulative emission reductions (over the same

[4] HI 41.5–2022 uses the term CER_{REF} for the analogous concept. In the September 2022 TP Final Rule, DOE discussed this decision to instead use CER_{STD} in the context of Federal energy conservation standards.

[5] HI 41.5–2022 provides additional instructions for testing circulator pumps to determine an Energy Rating value for different circulator pump control varieties.

[6] The average LCC savings refer to consumers that are affected by a standard and are measured relative to the efficiency distribution in the no-new-standards case, which depicts the market in the compliance year in the absence of new or amended standards. The simple PBP, which is designed to compare specific efficiency levels, is measured relative to the baseline product. *See* section IV.F of this document).

[7] All monetary values in this document are expressed in [2021] dollars.

[8] The quantity refers to full-fuel-cycle (''FFC'') energy savings. FFC energy savings includes the energy consumed in extracting, processing, and transporting primary fuels (*i.e.,* coal, natural gas, petroleum fuels), and, thus, presents a more complete picture of the impacts of energy efficiency standards. For more information on the FFC metric, see section IV.H.2 of this document.

period as for energy savings) of 15.8 million metric tons (''Mt'') [9] of carbon dioxide (''CO_2''), 7.7 thousand tons of sulfur dioxide (''SO_2''), 23.8 thousand tons of nitrogen oxides (''NO_X''), 102 thousand tons of methane (''CH_4''), 0.2 thousand tons of nitrous oxide (''N_2O''), and 0.05 tons of mercury (''Hg'').[10]

DOE estimates climate benefits from a reduction in greenhouse gases (GHG) using four different estimates of the social cost of CO_2 (''$SCCO_2$''), the social cost of methane (''$SCCH_4$''), and the social cost of nitrous oxide (''SCN_2O''). Together these represent the social cost of GHG (SCGHG).[11] DOE used interim SCGHG values developed by an Interagency Working Group on the Social Cost of Greenhouse Gases (IWG),[12] as discussed in section IV.L of this document. For presentational purposes, the climate benefits associated with the average SCGHG at a 3-percent discount rate are $0.80 billion. (DOE does not have a single central SCGHG point estimate and it emphasizes the importance and value of considering the benefits calculated using all four SCGHG estimates.)

DOE also estimates health benefits from SO_2 and NO_X emissions reductions.[13] DOE estimates the present value of the health benefits would be $0.65 billion using a 7-percent discount rate, and $1.45 billion using a 3-percent discount rate.[14] DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions.

Table I.3 summarizes the economic benefits and costs expected to result from the proposed standards for circulator pumps. In the table, total benefits for both the 3-percent and 7-percent cases are presented using the average GHG social costs with 3-percent discount rate, but the Department emphasizes the importance and value of considering the benefits calculated using all four SCGHG cases. The estimated total net benefits using each of the four cases are presented in section V.C.1 of this document.

TABLE I.3—SUMMARY OF ECONOMIC BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR CIRCULATOR PUMPS [TSL 2]

	Billion ($2020)
3% discount rate:	
Consumer Operating Cost Savings	3.41
Climate Benefits*	0.80
Health Benefits**	1.45
Total Benefits†	5.65
Consumer Incremental Product Costs‡	1.64
Net Benefits	4.02
7% discount rate:	
Consumer Operating Cost Savings	1.68
Climate Benefits* (3% discount rate)	0.80
Health Benefits**	0.65
Total Benefits†	3.12
Consumer Incremental Product Costs‡	0.95
Net Benefits	2.18

Note: This table presents the costs and benefits associated with product name shipped in 2026–2055. These results include benefits to consumers which accrue after 2055 from the products shipped in 2026–2055.

* Climate benefits are calculated using four different estimates of the SC-GHG (*see* section IV.L of this document). For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3 percent discount rate are shown, but the Department does not have a single central SC-GHG point estimate, and it emphasizes the importance of considering the benefits calculated using all four SC-GHG estimates.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. The health benefits are presented at real discount rates of 3 and 7 percent. See section IV.L of this document for more details.

[9] A metric ton is equivalent to 1.1 short tons. Results for emissions other than CO_2 are presented in short tons.

[10] DOE calculated emissions reductions relative to the no-new-standards case, which reflects key assumptions in the *Annual Energy Outlook 2022* (''*AEO2022*''). *AEO2022* represents current federal and state legislation and final implementation of regulations as of the time of its preparation. See section IV.K of this document for further discussion of *AEO2022* assumptions that effect air pollutant emissions.

[11] On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087) granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and present monetized benefits where appropriate and permissible under law.

[12] *See* Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide. Interim Estimates Under Executive Order 13990, Washington, DC, February 2021 (''February 2021 SCGHG TSD''*). www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf.*

[13] DOE estimated the monetized value of SO_2 and NO_X emissions reductions associated with electricity savings using benefit per ton estimates from the scientific literature. *See* section IV.L.2 of this document for further discussion.

[14] DOE estimates the economic value of these emissions reductions resulting from the considered TSLs for the purpose of complying with the requirements of Executive Order 12866.

† Total and net benefits include consumer, climate, and health benefits. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with 3-percent discount rate, but the Department does not have a single central SC-GHG point estimate. DOE emphasizes the importance and value of considering the benefits calculated using all four SC-GHG estimates. See Table V.18 for net benefits using all four SC-GHG estimates. On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087) granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and present monetized benefits where appropriate and permissible under law.

‡ Costs include incremental equipment costs as well as installation costs.

The benefits and costs of the proposed standards can also be expressed in terms of annualized values. The monetary values for the total annualized net benefits are (1) the reduced consumer operating costs, minus (2) the increase in product purchase prices and installation costs, plus (3) the value of the benefits of GHG and NO_X and SO_2 emission reductions, all annualized.[15] The national operating savings are domestic private U.S. consumer monetary savings that occur as a result of purchasing the covered equipment and are measured for the lifetime of circulator pumps shipped in 2026–2055. The benefits associated with reduced emissions achieved as a result of the proposed standards are also calculated based on the lifetime of circulator pumps shipped in 2026–2055.

Estimates of annualized benefits and costs of the proposed standards are shown in Table I.4. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and health benefits from reduced NOX and SO_2 emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated cost of the standards proposed in this rule is $93.5 million per year in increased equipment costs, while the estimated annual benefits are $165.8 in reduced equipment operating costs, $44.4 million in climate benefits, and $63.9 million in health benefits. In this case, the net benefit would amount to $180.5 million per year.

Using a 3-percent discount rate for all benefits and costs, the estimated cost of the proposed standards is $91.2 million per year in increased equipment costs, while the estimated annual benefits are $189.9 million in reduced operating costs, $44.4 million in climate benefits, and $80.8 million in health benefits. In this case, the net benefit would amount to $224.0 million per year.

TABLE I.4—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR CIRCULATOR PUMPS

[TSL 2]

	Million (2021$/year)		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate:			
Consumer Operating Cost Savings	189.9	185.7	194.0
Climate Benefits*	44.4	44.4	44.4
Health Benefits**	80.8	80.8	80.8
Total Benefits†	315.2	311.0	319.3
Consumer Incremental Product Costs‡	91.2	91.2	91.2
Net Benefits	224.0	219.8	228.1
7% discount rate:			
Consumer Operating Cost Savings	165.8	162.6	168.7
Climate Benefits* (3% discount rate)	44.4	44.4	44.4
Health Benefits**	63.9	63.9	63.9
Total Benefits†	274.1	271.0	277.0
Consumer Incremental Product Costs‡	93.5	93.5	93.5
Net Benefits	180.5	177.4	183.4

Note: This table presents the costs and benefits associated with circulator pumps shipped in 2026–2055. These results include benefits to consumers which accrue after 2055 from the products shipped in 2026–2055.

* Climate benefits are calculated using four different estimates of the global SCGHG (see section IV.L of this document. For presentational purposes of this table, the climate benefits associated with the average SCGHG at a 3 percent discount rate are shown, but the Department does not have a single central SCGHG point estimate, and it emphasizes the importance and value of considering the benefits calculated using all four SCGHG estimates.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for SO_2 and NO_X) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. The health benefits are presented at real discount rates of 3 and 7 percent. *See* section IV.L of this document for more details.

[15] To convert the time-series of costs and benefits into annualized values, DOE calculated a present value in 2022, the year used for discounting the NPV of total consumer costs and savings. For the benefits, DOE calculated a present value associated with each year's shipments in the year in which the shipments occur (*e.g.,*2030), and then discounted the present value from each year to 2022. Using the present value, DOE then calculated the fixed annual payment over a 30-year period, starting in the compliance year, that yields the same present value.

† Total and net benefits include consumer, climate, and health benefits. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SCGHG with 3-percent discount rate, but the Department does not have a single central SCGHG point estimate. DOE emphasizes the importance and value of considering the benefits calculated using all four SCGHG estimates. See Table V.18 for net benefits using all four SCGHG estimates. On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087) granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and present monetized benefits where appropriate and permissible under law.

‡ Costs include incremental equipment costs as well as installation costs.

DOE's analysis of the national impacts of the proposed standards is described in sections IV.H, IV.K and IV.L of this document.

D. Conclusion

DOE has tentatively concluded that the proposed standards represent the maximum improvement in energy efficiency that is technologically feasible and economically justified, and would result in the significant conservation of energy. Specifically, with regards to technological feasibility, equipment achieving these standard levels are already commercially available. As for economic justification, DOE's analysis shows that the benefits of the proposed standard exceed, to a great extent, the burdens of the proposed standards. Using a 7-percent discount rate for consumer benefits and costs and NO_X and SO_2 reduction benefits, and a 3-percent discount rate case for GHG social costs, the estimated cost of the proposed standards for circulator pumps is $93.5 million per year in increased circulator pumps costs, while the estimated annual benefits are $165.8 million in reduced circulator pumps operating costs, $44.4 million in climate benefits and $63.9 million in health benefits. The net benefit amounts to $180.5 million per year.

The significance of energy savings offered by a new or amended energy conservation standard cannot be determined without knowledge of the specific circumstances surrounding a given rulemaking.[16] Accordingly, DOE evaluates the significance of energy savings on a case-by-case basis.

As previously mentioned, the proposed standards are projected to result in estimated national energy savings of 0.45 quad, the equivalent of the electricity use of 4.4 million homes in one year. The NPV of consumer benefit for these projected energy savings is $0.73 billion using a discount rate of 7 percent, and $1.77 billion using a discount rate of 3 percent. The cumulative emissions reductions associated with these energy savings are 15.8 Mt of CO_2, 23.8 thousand tons of SO_2, 7.7 thousand tons of NO_X, 0.05 tons of Hg, 102.0 thousand tons of CH_4, and 0.18 thousand tons of N_2O. The estimated monetary value of the climate benefits from the reduced GHG emissions (associated with the average SC-GHG at a 3-percent discount rate) is $0.80 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions is $0.65 billion using a 7-percent discount rate and $1.45 billion using a 3-percent discount rate. As such, DOE has initially determined the energy savings from the proposed standard levels are ''significant'' within the meaning of 42 U.S.C. 6295(o)(3)(B). A more detailed discussion of the basis for these tentative conclusions is contained in the remainder of this document and the accompanying TSD.

DOE also considered more-stringent energy efficiency levels (''ELs'') as potential standards, and is still considering them in this rulemaking. However, DOE has tentatively concluded that the potential burdens of the more-stringent energy efficiency levels would outweigh the projected benefits.

Based on consideration of the public comments DOE receives in response to this document and related information collected and analyzed during the course of this rulemaking effort, DOE may adopt energy efficiency levels presented in this document that are either higher or lower than the proposed standards, or some combination of level(s) that incorporate the proposed standards in part.

II. Introduction

The following section briefly discusses the statutory authority underlying this proposed rule, as well as some of the relevant historical background related to the establishment of standards for circulator pumps.

A. Authority

EPCA authorizes DOE to regulate the energy efficiency of a number of consumer products and certain industrial equipment. Title III, Part C of EPCA, added by Public Law 95–619, Title IV, section 441(a) (42 U.S.C. 6311–6317, as codified), established the Energy Conservation Program for Certain Industrial Equipment, which sets forth a variety of provisions designed to improve energy efficiency. This equipment includes pumps, the subject of this document. (42 U.S.C. 6311(1)(A)))

The energy conservation program under EPCA consists essentially of four parts: (1) testing, (2) labeling, (3) the establishment of Federal energy conservation standards, and (4) certification and enforcement procedures. Relevant provisions of EPCA include definitions (42 U.S.C. 6311), test procedures (42 U.S.C. 6314), labeling provisions (42 U.S.C. 6315), energy conservation standards (42 U.S.C. 6313), and the authority to require information and reports from manufacturers (42 U.S.C. 6316; 42 U.S.C. 6296).

Federal energy efficiency requirements for covered equipment established under EPCA generally supersede State laws and regulations concerning energy conservation testing, labeling, and standards. (42 U.S.C. 6316(a) and (b); 42 U.S.C. 6297) DOE may, however, grant waivers of Federal preemption for particular State laws or regulations, in accordance with the procedures and other provisions set forth under EPCA. (*See* 42 U.S.C. 6316(a) (applying the preemption waiver provisions of 42 U.S.C. 6297))

Subject to certain criteria and conditions, DOE is required to develop test procedures to measure the energy efficiency, energy use, or estimated annual operating cost of each covered equipment. (42 U.S.C. 6295(o)(3)(A) and 42 U.S.C. 6295(r)) Manufacturers of covered equipment must use the Federal test procedures as the basis for: (1) certifying to DOE that their equipment complies with the applicable energy conservation standards adopted pursuant to EPCA (42 U.S.C. 6316(a); 42 U.S.C. 6295(s)), and (2) making representations about the efficiency of that equipment (42 U.S.C. 6314(d)).

[16] Procedures, Interpretations, and Policies for Consideration in New or Revised Energy Conservation Standards and Test Procedures for Consumer Products and Commercial/Industrial Equipment, 86 FR 70892, 70901 (Dec. 13, 2021).

Similarly, DOE must use these test procedures to determine whether the equipment complies with relevant standards promulgated under EPCA. (42 U.S.C. 6316(a); 42 U.S.C. 6295(s))

The DOE test procedures for circulator pumps appear at title 10 of the Code of Federal Regulations (''CFR'') part 431, subpart Y, appendix D.

DOE must follow specific statutory criteria for prescribing new or amended standards for covered equipment, including circulator pumps. Any new or amended standard for a covered equipment must be designed to achieve the maximum improvement in energy efficiency that the Secretary of Energy determines is technologically feasible and economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(A) and 42 U.S.C. 6295(o)(3)(B)) Furthermore, DOE may not adopt any standard that would not result in the significant conservation of energy. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3))

Moreover, DOE may not prescribe a standard: (1) for certain equipment, including circulator pumps, if no test procedure has been established for the product, or (2) if DOE determines by rule that the standard is not technologically feasible or economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(B)) In deciding whether a proposed standard is economically justified, DOE must determine whether the benefits of the standard exceed its burdens. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)) DOE must make this determination after receiving comments on the proposed standard, and by considering, to the greatest extent practicable, the following seven statutory factors:

(1) The economic impact of the standard on manufacturers and consumers of the products subject to the standard;

(2) The savings in operating costs throughout the estimated average life of the covered equipment in the type (or class) compared to any increase in the price, initial charges, or maintenance expenses for the covered equipment that are likely to result from the standard;

(3) The total projected amount of energy (or as applicable, water) savings likely to result directly from the standard;

(4) Any lessening of the utility or the performance of the covered equipment likely to result from the standard;

(5) The impact of any lessening of competition, as determined in writing by the Attorney General, that is likely to result from the standard;

(6) The need for national energy and water conservation; and

(7) Other factors the Secretary of Energy (''Secretary'') considers relevant. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(I)–(VII))

Further, EPCA establishes a rebuttable presumption that a standard is economically justified if the Secretary finds that the additional cost to the consumer of purchasing a product complying with an energy conservation standard level will be less than three times the value of the energy savings during the first year that the consumer will receive as a result of the standard, as calculated under the applicable test procedure. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(iii))

EPCA also contains what is known as an ''anti-backsliding'' provision, which prevents the Secretary from prescribing any amended standard that either increases the maximum allowable energy use or decreases the minimum required energy efficiency of covered equipment. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(1)) Also, the Secretary may not prescribe an amended or new standard if interested persons have established by a preponderance of the evidence that the standard is likely to result in the unavailability in the United States in any covered equipment type (or class) of performance characteristics (including reliability), features, sizes, capacities, and volumes that are substantially the same as those generally available in the United States. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(4))

Additionally, EPCA specifies requirements when promulgating an energy conservation standard for covered equipment that has two or more subcategories. DOE must specify a different standard level for a type or class of product that has the same function or intended use, if DOE determines that products within such group: (A) consume a different kind of energy from that consumed by other covered equipment within such type (or class); or (B) have a capacity or other performance-related feature which other products within such type (or class) do not have and such feature justifies a higher or lower standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q)(1)) In determining whether a performance-related feature justifies a different standard for a group of products, DOE must consider such factors as the utility to the consumer of the feature and other factors DOE deems appropriate. *Id.* Any rule prescribing such a standard must include an explanation of the basis on which such higher or lower level was established. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q)(2))

B. Background

As stated, EPCA includes ''pumps'' among the industrial equipment listed as ''covered equipment'' for the purpose of Part A–1, although EPCA does not define the term ''pump.'' (42 U.S.C. 6311(1)(A)) In a final rule published January 25, 2016, DOE established a definition for ''pump,'' associated definitions, and test procedures for certain pumps. 81 FR 4086, 4090. (''January 2016 TP final rule''). ''Pump'' is defined as equipment designed to move liquids (which may include entrained gases, free solids, and totally dissolved solids) by physical or mechanical action and includes a bare pump and, if included by the manufacturer at the time of sale, mechanical equipment, driver, and controls. 10 CFR 431.462. Circulator pumps fall within the scope of this definition.

While DOE has defined ''pump'' broadly, the test procedure established in the January 2016 TP final rule is applicable only to certain categories of clean water pumps,[17] specifically those that are end suction close-coupled; end suction frame mounted/own bearings; in-line (''IL''); radially split, multi-stage, vertical, in-line diffuser casing; and submersible turbine (''ST'') pumps with the following characteristics:

• 25 gallons per minute (''gpm'') and greater (at best efficiency point (''BEP'') at full impeller diameter);
• 459 feet of head maximum (at BEP at full impeller diameter and the number of stages specified for testing);
• design temperature range from 14 to 248 °F;
• designed to operate with either (1) a 2- or 4-pole induction motor, or (2) a non-induction motor with a speed of rotation operating range that includes speeds of rotation between 2,880 and 4,320 revolutions per minute (''rpm'') and/or 1,440 and 2,160 rpm, and in either case, the driver and impeller must rotate at the same speed;
• 6-inch or smaller bowl diameter for ST pumps;
• A specific speed less than or equal to 5,000 for ESCC and ESFM pumps;
• Except for: fire pumps, self-priming pumps, prime-assist pumps, magnet driven pumps, pumps designed to be used in a nuclear facility subject to 10

[17] A ''clean water pump'' is a pump that is designed for use in pumping water with a maximum non-absorbent free solid content of 0.016 pounds per cubic foot, and with a maximum dissolved solid content of 3.1 pounds per cubic foot, provided that the total gas content of the water does not exceed the saturation volume, and disregarding any additives necessary to prevent the water from freezing at a minimum of 14 °F. 10 CFR 431.462.

CFR part 50, ''Domestic Licensing of Production and Utilization Facilities''; and pumps meeting the design and construction requirements set forth in any relevant military specifications.[18]

10 CFR 431.464(a)(1). The pump categories subject to the current test procedures are referred to as ''general pumps'' in this document. As stated, circulator pumps are not general pumps.

DOE also published a final rule establishing energy conservation standards applicable to certain classes of general pumps. 81 FR 4368 (Jan. 26, 2016) (''January 2016 ECS final rule''); *see also,* 10 CFR 431.465.

The January 2016 TP final rule and the January 2016 ECS final rule implemented the recommendations of the Commercial and Industrial Pump Working Group (''CIPWG'') established through the Appliance Standards Rulemaking Federal Advisory Committee (''ASRAC'') to negotiate standards and a test procedure for general pumps. (Docket No. EERE–2013–BT–NOC–0039) The CIPWG approved a term sheet containing recommendations to DOE on appropriate standard levels for general pumps, as well as recommendations addressing issues related to the metric and test procedure for general pumps (''CIPWG recommendations''). (Docket No. EERE–2013–BT–NOC–0039, No. 92) Subsequently, ASRAC approved the CIPWG recommendations. The CIPWG recommendations included initiation of a separate rulemaking for circulator pumps. (Docket No. EERE–2013–BT–NOC–0039, No. 92, Recommendation #5A at p. 2)

On February 3, 2016, DOE issued a notice of intent to establish the circulator pumps working group to negotiate a notice of proposed rulemaking (''NOPR'') for energy conservation standards for circulator pumps to negotiate, if possible, Federal standards and a test procedure for circulator pumps and to announce the first public meeting. 81 FR 5658. The members of the Circulator Pump Working Group (''CPWG'') were selected to ensure a broad and balanced array of interested parties and expertise, including representatives from efficiency advocacy organizations and manufacturers. Additionally, one member from ASRAC and one DOE representative were part of the CPWG. Table II.1 lists the 15 members of the CPWG and their affiliations.

TABLE II.1—ASRAC CIRCULATOR PUMP WORKING GROUP MEMBERS AND AFFILIATIONS

Member	Affiliation
Charles White	Plumbing-Heating-Cooling Contractors Association.
Gabor Lechner	Armstrong Pumps, Inc.
Gary Fernstrom	California Investor-Owned Utilities.
Joanna Mauer	Appliance Standards Awareness Project.
Joe Hagerman	U.S. Department of Energy.
Laura Petrillo-Groh	Air-Conditioning, Heating, and Refrigeration Institute.
Lauren Urbanek	Natural Resources Defense Council.
Mark Chaffee	TACO, Inc.
Mark Handzel	Xylem Inc.
Peter Gaydon	Hydraulic Institute.
Richard Gussert	Grundfos Americas Corporation.
David Bortolon	Wilo Inc.
Russell Pate	Rheem Manufacturing Company.
Don Lanser	Nidec Motor Corporation.
Tom Eckman	Northwest Power and Conservation Council (ASRAC member).

The CPWG commenced negotiations at an open meeting on March 29, 2016, and held six additional meetings to discuss scope, metrics, and the test procedure. The CPWG concluded its negotiations for test procedure topics on September 7, 2016, with a consensus vote to approve a term sheet containing recommendations to DOE on scope, definitions, metric, and the basis of the test procedure (''September 2016 CPWG Recommendations''). The September 2016 CPWG Recommendations are available in the CPWG docket. (Docket No. EERE–2016–BT–STD–0004, No. 58)

The CPWG continued to meet to address potential energy conservation standards for circulator pumps. Those meetings began on November 3–4, 2016 and concluded on November 30, 2016, with approval of a second term sheet (''November 2016 CPWG Recommendations'') containing CPWG recommendations related to energy conservation standards, applicable test procedure, labeling and certification requirements for circulator pumps (Docket No. EERE–2016–BT–STD–0004, No. 98). Whereas the September 2016 CPWG Recommendations are discussed in the September 2022 TP Final Rule, the November 2016 CPWG Recommendations are summarized in section III.A of this document. ASRAC subsequently voted unanimously to approve the September and November 2016 CPWG Recommendations during a December meeting. (Docket No. EERE–2013–BT–NOC–0005, No. 91 at p.2) [19]

In a letter dated June 9, 2017, Hydraulic Institute (''HI'') expressed its support for the process that DOE initiated regarding circulator pumps and encouraged the publishing of a NOPR and a final rule by the end of 2017. (Docket No. EERE–2016–BT–STD–0004, HI, No.103 at p. 1) In response to an early assessment review RFI published September 28, 2020 regarding the existing test procedures for general pumps (85 FR 60734, ''September 2020 Early Assessment RFI''), HI commented that it continues to support the recommendations from the CPWG. (Docket No. EERE–2020–BT–TP–0032, HI, No. 6 at p. 1) NEEA also referenced

[18] *E.g.,* MIL–P–17639F, ''Pumps, Centrifugal, Miscellaneous Service, Naval Shipboard Use'' (as amended); MIL–P–17881D, ''Pumps, Centrifugal, Boiler Feed, (Multi-Stage)'' (as amended); MIL–P–17840C, ''Pumps, Centrifugal, Close-Coupled, Navy Standard (For Surface Ship Application)'' (as amended); MIL–P–18682D, ''Pump, Centrifugal, Main Condenser Circulating, Naval Shipboard'' (as amended); and MIL–P–18472G, ''Pumps, Centrifugal, Condensate, Feed Booster, Waste Heat Boiler, And Distilling Plant'' (as amended). Military specifications and standards are available at *https://everyspec.com/MIL-SPECS.*

[19] All references in this document to the approved recommendations included in 2016 Term Sheets are noted with the recommendation number and a citation to the appropriate document in the CPWG docket (*e.g.,* Docket No. EERE–2016–BT–STD–0004, No. #, Recommendation #X at p. Y). References to discussions or suggestions of the CPWG not found in the 2016 Term Sheets include a citation to meeting transcripts and the commenter, if applicable (*e.g.,* Docket No. EERE–2016–BT–STD–0004, [Organization], No. X at p. Y).

the September 2016 CPWG Recommendations and recommended that DOE adopt test procedures for circulator pumps in the pumps rulemaking or a separate rulemaking. (Docket No. EERE–2020–BT–TP–0032, NEEA, No. 8 at p. 8)

On May 7, 2021, DOE published a request for information related to test procedures and energy conservation standards for circulator pumps. 86 FR 24516 (''May 2021 RFI'').

DOE received comments in response to the May 2021 RFI from the interested parties listed in Table II.2.

TABLE II.2—LIST OF COMMENTERS WITH WRITTEN SUBMISSIONS IN RESPONSE TO THE MAY 2021 RFI

Commenter(s)	Reference in this final rule	Docket No.	Commenter type
People's Republic of China	China	EERE–2016–BT–STD–0004–0111	Country.
Hydraulic Institute	HI	EERE–2016–BT–STD–0004–0112	Trade Association.
Grundfos Americas Corporation	Grundfos	EERE–2016–BT–STD–0004–0113	Manufacturer.
Appliance Standards Awareness Project, American Council for an Energy-Efficient Economy, Natural Resources Defense Council.	Advocates	EERE–2016–BT–STD–0004–0114	Efficiency Organization.
Northwest Energy Efficiency Alliance	NEEA	EERE–2016–BT–STD–0004–0115	Efficiency Organization.
Pacific Gas and Electric Company, San Diego Gas and Electric, and Southern California Edison; collectively, the California Investor-Owned Utilities.	CA IOUs	EERE–2016–BT–STD–0004–0116	Utility.
Anonymous Commenter	N/A	EERE–2016–BT–STD–0004–0117	Anonymous.[20]

A parenthetical reference at the end of a comment quotation or paraphrase provides the location of the item in the public record.[21]

DOE published a notice of proposed rulemaking (NOPR) for the test procedure on December 20, 2021, presenting DOE's proposals to establish a circulator pump test procedure (86 FR 72096) (hereafter, the ''December 2021 TP NOPR''). DOE held a public meeting related to this NOPR on February 2, 2022. DOE published a final rule for the test procedure on September 19, 2022 (''September 2022 TP Final Rule''). The test procedure final rule established definitions, testing methods and a performance metric, requirements regarding sampling and representations of energy consumption and certain other metrics, and enforcement provisions for circulator pumps.

C. Deviation From Appendix A

In accordance with section 3(a) of 10 CFR part 430, subpart C, appendix A (''Appendix A''), DOE notes that it is deviating from two provisions in appendix A regarding the NOPR stage for an energy conservation standard rulemaking. First, section 6(f)(2) of appendix A specifies that the length of the public comment period for a NOPR will vary depending upon the circumstances of the particular rulemaking but will not be less than 75 calendar days. For this NOPR, DOE is providing a 60-day comment period, as required by EPCA. 42 U.S.C. 6316(a); 42 U.S.C. 6295(p). Second, section 6(a)(2) of appendix A states that if DOE determines in is appropriate to proceed with a rulemaking, then the preliminary stages of a rulemaking to issue an energy conservation standard would include either a framework document and preliminary analysis or, alternatively, an advance notice of proposed rulemaking. According to section 6(a)(2) of appendix A, DOE may also optionally issue requests for information and notices of data availability.

As stated in section II.B of this document, DOE established a working group (the CPWG) to negotiate potential energy conservation standards for circulator pumps, which culminated at a consensus agreement (the November 2016 CPWG Recommendations) recommending that energy conservation standards for circulator pumps be adopted at TSL2, the level proposed in this NOPR. The CPWG held a series of formal and informal meetings, minutes and supporting material for which are posted in Docket No. EERE–2016–BT–STD–0004.

Additionally, as stated in section II.B of this document, on May 7, 2021, DOE published a request for information related to test procedures and energy conservation standards for circulator pumps in which it initially provided a 60-day comment period. 86 FR 24516 (''May 2021 RFI''). Subsequently, in response to requests, DOE provided a 24-day extension to that initial comment period, for a total comment period of 84 days. 86 FR 28298.

DOE has relied on many of the same analytical assumptions and approaches as used in developing analysis supporting the standard level of TSL2 which was the consensus recommendation of the CWPG and which was supported by several commenters and which no commenters opposed. (HI, No. 112 at p. 6; Grundfos, No. 113 at p. 6; NEEA, No. 115 at p. 3; Advocates, No. 114 at p. 1; CA IOUs, No. 116 at p. 5)

Considering the opportunity for comment and input afforded the CWPG by the negotiation process, including the opportunity to vote on a consensus level for energy conservation standards, the 84-day comment period of the May 2021 RFI in which the CPWG-recommended standard level was discussed, and the close adherence of the methods and analysis used in this NOPR to support a proposed standard level of TSL 2, interested parties have been provided substantial opportunity to provide input. Therefore, DOE believes a 60-day comment period is appropriate and will provide interested parties with a meaningful opportunity to comment on the proposed rule.

Regarding the provision in section 6(a)(2) of appendix A to issue either a framework document and preliminary analysis or, alternatively, an advance notice of proposed rulemaking as the preliminary rulemaking documents, the function of these documents is to lay out for interested parties and the public DOE's planned approach and provide opportunity for comment had already been performed by the CPWG meeting process. Interested parties were offered opportunity to not only observe and comment on but even participate in that process. As discussed in section II.B of this document, many did. Table II.1 lists the 15 members of the CPWG and their

[20] The Anonymous comment did not substantively address the subject of this rulemaking.

[21] The parenthetical reference provides a reference for information located in the docket of DOE's rulemaking to develop test procedures for circulator pumps. EERE–2016–BT–TP–0033 (Docket No. EERE–2016–BT–TP–0033, which is maintained at *www.regulations.gov*). The references are arranged as follows: (commenter name, comment docket ID number, page of that document).

affiliations. The proceedings of the working group and related ASRAC activities have been documented and available for review respectively in the rulemaking docket (EERE–2016–BT–STD–0004) and non-rulemaking, ASRAC docket (Docket No. EERE–2013–BT–NOC–0005).

As discussed in section II.B, the CPWG approved two term sheets which represented the group's consensus recommendations. The second term sheet, referred to in this NOPR as the ''November 2016 CPWG Recommendations'' contained the CPWG recommendations related to energy conservation standards, applicable test procedure, labeling and certification requirements for circulator pumps. (Docket No. EERE–2016–BT–STD–0004, No. 98) The proposals in this NOPR closely mirror the November 2016 CPWG Recommendations, which are accordingly summarized in this section.

III. General Discussion

DOE developed this proposal after considering oral and written comments, data, and information from interested parties that represent a variety of interests. The following discussion addresses issues raised by these commenters.

A. November 2016 CPWG Recommendations

As discussed in section II.B, the CPWG approved two term sheets which represented the group's consensus recommendations. The second term sheet, referred to in this NOPR as the ''November 2016 CPWG Recommendations'' contained the CPWG recommendations related to energy conservation standards, applicable test procedure, labeling and certification requirements for circulator pumps. (Docket No. EERE–2016–BT–STD–0004, No. 98) The proposals in this NOPR closely mirror the November 2016 CPWG Recommendations, which are accordingly summarized in this section.

1. Energy Conservation Standard Level

The CPWG recommendation that each circulator pump be required to meet an applicable minimum efficiency standard. Specifically, the recommendation was that each pump must have a CEI [22] of less than or equal to 1.00. Among the numbered efficiency levels considered by the CPWG as potential standard levels, the agreed level was EL2 (*i.e.,* CEI less than or equal to 1.00).

In response to the May 2021 RFI, several stakeholders commented in support of the CPWG's recommendation of energy conservation standards at EL2. HI commented that it supported the work and recommendations of the CPWG. (HI, No. 112 at p. 6) Grundfos recommended DOE adopt EL2, the recommended standard level of the CPWG. (Grundfos, No. 113 at p. 6) NEEA commented it believes EL 2 is still appropriate and will result in significant energy savings nationally. (NEEA, No. 115 at p. 3) The Advocates commented that DOE should quickly adopt energy conservation standards for circulator pumps in accordance with the CPWG recommendations. (Advocates, No. 114 at p. 1) The CA IOUs commented that they support adopting the provisions of the CPWG term sheets, including the recommended energy conservation standard level of EL2. CA IOUs (CA IOUs, No. 116 at p.5)

No comments were received arguing against adoption of the CPWG-recommended standard level.

In the May 2021 RFI, DOE requested comment on whether any changes in the market since publication of the 2016 Term Sheets could make the CPWG's recommendation for EL 2 no longer valid. Grundfos, HI, NEEA responded stating there were little to no changes and the CPWG's recommendation of EL2 is still appropriate. (Grundfos, No. 113 at p. 10; HI, No. 112 at p. 11; NEEA, No. 115 at p. 2) HI estimated that standards at EL 2 would eliminate all permanent-split capacitor (''PSC'') motor circulator pumps which is the predominant product sold today. (*Id.*) Grundfos recommended that DOE adopt EL 2 as the standard, which would force the market to electronically commutated motor (ECM) products and remove 4% of ECMs currently available (based on CPWG data). (Grundfos, No. 113 at p. 7)

Overall, the CPWG-recommended standard level appears well supported by commenters. As described in section V.C.1, DOE is proposing in this NOPR to adopt energy conservation standards for circulator pumps at TSL 2, which

As stated in section I, CEI was defined in the September 2022 TP Final Rule consistent with the November 2016 CPWG Recommendations as shown in equation (2), and consistent with Section 41.5.3.2 of HI 41.5–2022. (87 FR 57264).

$$CEI = \left[\frac{\mathrm{CER}}{CER_{STD}}\right] \quad \textbf{(2)}$$

Where:

CER = circulator energy rating (hp); and
CER_{STD} = circulator energy rating for a minimally compliant circulator pump serving the same hydraulic load.

The specific formulation CER, in turn, varies according to circulator pump control variety, but in all cases is a function of measured pump input power when operated under certain conditions, as described in the September 2022 TP Final Rule.

Relatedly, CER_{STD} represents CER for a circulator pump that is minimally compliant with DOE's energy conservation standards with the same hydraulic horsepower as the tested pump, as determined in accordance with the specifications at paragraph (i) of § 431.465. (87 FR 57264)

The November 2016 CPWG Recommendations contained a proposed method for calculating CER_{STD} [23] as shown in Equation (3):

[22] The CPWG recommendations predated establishment of the current metric, called ''CEI'', and instead used the analogous term ''PEI_{CIRC}''. In the December 2021 TP NOPR, DOE proposed to adopt the ''CEI'' nomenclature instead ''PEI_{CIRC}'' to ''CEI'' based, in part, on comments received, to remain consistent with terminology used in HI 41.5, and to avoid potential confusion with the nomenclature. After receiving favorable comments on its proposal, DOE adopted the CEI nomenclature in the September 2022 TP Final Rule.

[23] The CPWG recommendations predated establishment of the current term ''CER_{STD}'' and instead used the analogous term ''$PER_{CIRC,STD}$''. In the December 2021 TP NOPR, DOE proposed to adopt the ''CER_{STD}'' nomenclature instead ''$PER_{CIRC,STD}$'' because DOE believed that the terminology CER_{STD} is more reflective of Federal energy conservation standards. After receiving no opposition on its proposal, DOE adopted the CEI nomenclature in the September 2022 TP Final Rule.

$$CER_{STD} = \sum_i \omega_i \left(P_i^{in,STD}\right) \tag{3}$$

Where:

ω_i = weight at each test point i, specified in Recommendation #2B

$P_i^{in,STD}$ = reference power input to the circulator pump driver at test point i, calculated using the equations and method specified in Recommendation #2C

i = test point(s), defined as 25%, 50%, 75%, and 100% of the flow at best efficiency point (BEP).

The November 2016 CPWG Recommendations also included a recommended weighting factor of 25% for each respective test point, i. (''Recommendation #2B'').

The November 2016 CPWG Recommendations also included (''Recommendation #2C'') a recommended reference input power, $P_i^{in,STD}$ as described in equation (4).

$$P_i^{in,STD} = \frac{P_{u,i}}{\alpha_i * \frac{\eta_{WTW,100\%}}{100}} \tag{4}$$

Where:

$P_{u,i}$ = tested hydraulic power output of the pump being rated at test point i, in HP

$\eta_{WTW,100\neq}$ = reference BEP circulator pump efficiency at the recommended standard level (%), calculated using the equations and values specified in Recommendation #2D

α_i = part load efficiency factor at each test point i, specified in Recommendation #2E

i = test point(s), defined as 25%, 50%, 75%, and 100% of the flow at best efficiency point (BEP).

The November 2016 CPWG Recommendations also included a reference efficiency at BEP at the CPWG-recommended standard level, $\eta_{WTW,100\%}$, (''Recommendation #2D'') which varies by circulator pump hydraulic output power.

Specifically, for circulator pumps with BEP hydraulic output power $P_{u,100\%}$ <1 HP, the reference efficiency at BEP (ηWTW,100%) should be determined using equation (5):

$$\eta_{WTW,100\%} = A * \ln\left(P_{u,100\%} + B\right) + C \tag{5}$$

Where:

$\eta_{WTW,100\%}$ = reference BEP pump efficiency at the recommended standard level (%),

$P_{u,100\%}$ = tested hydraulic power output of the pump being rated at BEP, in HP

For the CPWG-recommended standard level, the constants A, B, and C used in equation would have the following values:

TABLE III.1—CPWG-RECOMMENDED REFERENCE PUMP WTW,100% CONSTANTS

A	B	C
10.00	.001141	67.78

For circulator pumps with BEP hydraulic output power $P_{u,100\%}$ ≥1 HP, the reference efficiency at BEP (ηWTW,100%) would have a constant value of 67.79.

Additionally, the November 2016 CPWG Recommendations included a part-load efficiency factor (α_i, as appears in equation (4)), which varies according to test point (''Recommendation #2E). Specifically, α_i would have values as listed in Table III.2.

TABLE III.2—CPWG-RECOMMENDED PART-LOAD EFFICIENCY

i	Corresponding α_i
25%	0.4843
50%	0.7736
75%	0.9417
100% [24]	1

This CPWG-recommended equation structure is used to characterize the standard level proposed in this NOPR, with certain inconsequential changes to variable names.

2. Labeling Requirements

Under EPCA, DOE has certain authority to establish labeling requirements for covered equipment. (42 U.S.C. 6315) The November 2016 CPWG Recommendations contained one recommendation regarding labeling requirements, which was that both model number and CEI [25] be included on the circulator nameplate (Docket No. EERE–2016–BT–STD–0004, No. 98 Recommendation #3 at p. 4).

In response to the May 2021 RFI, the Advocates commented in support of establishing labeling requirements for

[24] The November 2016 CPWG Recommendations did not explicitly include a value for the part-load efficiency factor, α_i, in Recommendation #2E. Nonetheless, Recommendation #2C makes clear that a value for the part-load efficiency factor, α_i, is required to calculate reference input power, which calls for a value at test point i = 100%. DOE infers the omission of $\alpha_{100\%}$ from Recommendation #2E to reflect that i = 100% corresponds to full-load, and thus imply no part-load-driven reduction in efficiency and, by extension, a load coefficient of unity. DOE is making this assumption that $\alpha_{100\%}$ = 1 explicit by including it in this table, which is otherwise identical to that of CPWG Recommendation #2E.

[25] The CPWG recommended that ''PEI'' be included in a potential labeling requirement which, as described previously, is analogous to CEI.

circulator pumps (Advocates, No. 114 at p. 1). No commenters argued against establishing labeling requirements for circulator pumps.

DOE is reviewing the potential benefits of establishing labeling requirements for circulator pumps and may share the results of such evaluation in a separate notice. Accordingly, in this NOPR, DOE is not proposing specific labeling requirements for circulator pumps, but DOE may consider such requirements for circulator pumps, including those recommended by the CPWG, in a separate rulemaking.

3. Certification Reports

Under EPCA, DOE has the authority to require information and reports from manufacturers with respect to the energy efficiency or energy use. (42 U.S.C. 6316; 42 U.S.C. 6296).

The November 2016 CPWG Recommendations contained one recommendation regarding certification reporting requirements. Specifically, the CPWG recommended that the following information should be included in both certification reports and the public CCMS database:

- Manufacturer name
- Model number
- CEI [26]
- Flow (in gallons per minute) and Head (in feet) at BEP
- Tested control setting
- Input power at measured data points

(Docket No. EERE–2016–BT–STD–0004, No. 98 Recommendation #4 at p. 4)

The CPWG also recommended that certain additional information be permitted but not mandatorily included in both certification reports and the public CCMS database. (Docket No. EERE–2016–BT–STD–0004, No. 98 Recommendation 4 at p. 1) The recommended optional information consisted of: true RMS current, true RMS voltage, real power, and the resultant power factor at measured data points. (Docket No. EERE–2016–BT–STD–0004, No. 98 Recommendation #4 at p. 4)

DOE is not proposing certification or reporting requirements for circulator pumps in this NOPR. Instead, DOE may consider proposals to address amendments to the certification requirements and reporting for circulator pumps under a separate rulemaking regarding appliance and equipment certification.

[26] CEI had not been established at the time of the November 2016 CPWG Recommendations, which instead referred to this value as ''PEI_{CIRC}''.

B. Equipment Classes and Scope of Coverage

When evaluating and establishing energy conservation standards, DOE divides covered equipment into equipment classes by the type of energy used or by capacity or other performance-related features that justify differing standards. In making a determination whether a performance-related feature justifies a different standard, DOE must consider such factors as the utility of the feature to the consumer and other factors DOE determines are appropriate. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q))

In this NOPR, DOE proposes to align the scope of energy conservation standards for circulator pumps with that of the circulator pumps test procedure. 87 FR 57264. Specifically, this NOPR proposes to apply energy conservation standards to all circulator pumps that are also clean water pumps, including on-demand circulator pumps and circulators-less-volute, and excluding submersible pumps and header pumps.

This scope is consistent with the recommendations of the CPWG. DOE identified no basis to change the scope of energy conservations standard for circulator pumps relative to the scope of test procedures adopted in the September 2022 Final Rule. Accordingly, the scope of proposed energy conservation standards aligns with that of the test procedure. Comments related to scope are discussed and considered in the test procedure final rule.

Both of these proposals—scope and equipment classes—match the recommendations of the CPWG, which are summarized in this section. They are discussed further in section IV.A.1 of this document.

1. CPWG Recommendations

a. Scope

The September 2016 CPWG Recommendations addressed the scope of a circulator pumps rulemaking. Specifically, the CPWG recommended that the scope of a circulator pumps test procedure and energy conservation standards cover clean water pumps (as defined at 10 CFR 431.462) distributed in commerce with or without a volute and that are one of the following categories: wet rotor circulator pumps, dry rotor close-coupled circulator pumps, and dry rotor mechanically coupled circulator pumps. The CPWG also recommended that the scope exclude submersible pumps and header pumps. 86 FR 24516, 24520; (Docket No. EERE–2016–BT–STD–0004, No. 58, Recommendations #1A, 2A and 2B at p. 1–2) In response to the May 2021 RFI, HI and Grundfos stated that they believed all circulator pumps are included in the scope defined by the CPWG in the term sheets. (HI, No. 112 at p. 8; Grundfos, No. 113 at p. 7). DOE's proposal aligns with the scope recommended by the CPWG, consistent with the September 2022 TP Final Rule.

b. Definitions

The CPWG also recommended several definitions relevant to scope. DOE notes that, generally, definitions recommended by the CPWG rely on terms previously defined in the January 2016 TP final rule, including ''close-coupled pump,'' ''mechanically-coupled pump,'' ''dry rotor pump,'' ''single axis flow pump,'' and ''rotodynamic pump.'' 81 FR 4086, 4146–4147; 10 CFR 431.462. In addition, the recommended definition for ''submersible pump'' is the same as that already defined in a 2017 test procedure final rule for dedicated-purpose pool pumps (''August 2017 DPPP TP final rule''). 82 FR 36858, 36922 (August 7, 2017); 10 CFR 431.462.

In the September 19, 2022 TP Final Rule DOE established a number of definitions related to circulator pumps as follows. 87 FR 57264. Specifically, DOE defined: ''circulator pump'', ''wet rotor circulator pump'', ''dry rotor, two-piece circulator pump'', ''dry rotor, three-piece circulator pump'', ''horizontal motor'', ''header pump'', and ''circulator-less-volute.'' (87 FR 57264)

''Circulator pump'' was defined to include both wet- and dry-rotor designs and to include circulators-less-volute, which are distributed in commerce without a volute and for which a paired volute is also distributed in commerce. Header pumps, by contrast, are those without volutes and for which no paired volute is available in commerce. (87 FR 57264)

In the September 2022 TP Final Rule (87 FR 57264) DOE did not propose a new definition for submersible circulator pumps, instead signaling applicability of an established term, ''submersible pump'', which was defined in the 2017 test procedure final rule for dedicated-purpose pool pumps (''August 2017 DPPP TP final rule''). 82 FR 36858, 36922 (August 7, 2017):

Submersible pump means a pump that is designed to be operated with the motor and bare pump fully submerged in the pumped liquid. 10 CFR 431.462.

DOE proposes to maintain these definitions from the September 2022 TP Final Rule in the standards for circulator pumps.

c. Equipment Classes

The CPWG recommended that all circulator pumps be analyzed in a single equipment class. (Docket No. EERE–2016–BT–STD–0004, No. 98, Recommendation #1 at p. 1) DOE's proposal aligns with the recommendation of the CPWG. Equipment classes are discussed further in section IV.A.1 of this document.

d. Small Vertical In-Line Pumps

The CPWG recommended that DOE analyze and establish energy conservation standards for small vertical in-line pumps (''SVILs'') with a compliance date equivalent to the previous energy conservation standards final rule (81 FR 4367, Jan. 26, 2016) for general (and not circulator) pumps. (Docket No. EERE–2016–BT–STD–0004, No. 58, Recommendation #1B at p. 1–2) The recommendation was that the standards for SVILs be similar in required performance to those of general pumps. (Docket No. EERE–2016–BT–STD–0004, No. 58, Recommendation #1B at p. 2) In addition to energy conservation standards for SVILs, the CPWG recommended SVILs be evaluated using the same test metric as general pumps. *Id.*

In their response to the May 2021 RFI, Advocates requested that standards for small vertical in-line pumps (''SVILs'') be established that are comparable to those of commercial and industrial inline pumps, as the CPWG recommended in 2016 (Advocates, No. 114 at p. 1). Consistent with those sentiments, DOE proposed to extend commercial and industrial pump test procedures to SVILs in a separate notice of proposed rulemaking. 87 FR 21268 (Apr. 11, 2022) (April 2022 NOPR). That test procedure, if finalized, may allow evaluation of energy conservation standards for SVILs as part of a commercial and industrial pumps rulemaking process. However, subsequent to the April 2022 NOPR, DOE published a notice of data availability (NODA) in which DOE noted that during interviews conducted after the April 2022 NOPR, manufacturers provided conflicting suggestions for how DOE should conduct its SVIL analysis, including that some manufacturers suggested that potential SVIL standards should be equivalent to any future standards for circulator pumps. DOE received conflicting feedback on whether circulator pumps and SVILs would compete with, or act as substitutes for, each other. Some manufacturers stated that an SVIL would never be substituted for a circulator pump, while others said that it was possible. 87 FR 49537 (Aug. 11, 2022). In that NODA, DOE request comment on specific applications for which SVILs could be used instead of circulator pumps and how an SVIL would need to be modified for use in these applications, and potential benefits and drawbacks of setting standards for SVILs that align with circulator pumps versus setting standards for SVILs that align with in-line pumps. *Id.*

At this time, DOE has tentatively determined to maintain its approach to address energy conservation standards for circulator pumps only in this rulemaking, separately from SVILs. DOE has not received adequate data or information at this time to suggest that DOE should address standards for SVILs along with the circulator pumps within the scope of this NOPR. Accordingly, DOE is proposing not to include SVILs within the scope of the energy conservation standards considered in this NOPR. Relatedly, the September 2022 TP Final Rule did not adopt test procedures for SVILs. DOE will continue to evaluate manufacturer and stakeholder feedback related to this issue and take any additional information into consideration as it may relate to including SVILs, or a subset of SVILs, within the scope of this rulemaking.

DOE requests comment on its approach to exclude SVILs from the scope of this NOPR, and whether DOE should consider standards for any SVILs as part of this rulemaking.

C. Test Procedure

EPCA sets forth generally applicable criteria and procedures for DOE's adoption and amendment of test procedures. (42 U.S.C. 6314(a)) Manufacturers of covered equipment must use these test procedures to certify to DOE that their product complies with energy conservation standards and to quantify the efficiency of their product. DOE's current energy conservation standards for circulator pumps are expressed in terms of circulator energy index (''CEI''). CEI represents the weighted average electric input power to the driver over a specified load profile, normalized with respect to a circulator pump serving the same hydraulic load that has a specified minimum performance level. [27] (*See* 10 CFR 431.464(c)).

[27] The performance of a comparable pump that has a specified minimum performance level is referred to as the circulator energy rating (''CER'').

a. Control Mode

Circulator pumps may be equipped with speed controls that govern their response to settings or signals. DOE's test procedure contains definitions and test methods applicable to pressure controls, temperature controls, manual speed controls, external input signal controls, and no controls (*i.e.,* full speed operation only). [28] Section B.1 of appendix D to subpart Y of 10 CFR part 431 specifies that circulator pumps without one of the identified control varieties (*i.e.,* pressure control, temperature control, manual speed control or external input signal control) are tested at full speed.

Some circulator pumps operate in only a single control mode (*i.e.,* selected variety), whereas others are capable of operating in any of several control modes. As discussed in the September 2022 TP Final Rule, circulator pump energy performance typically varies by control variety, for circulator pumps equipped with more than one control variety. In the September 2022 TP Final Rule, DOE summarized and responded to a variety of stakeholder comments which discussed advantages and disadvantages of various potential requirements regarding the control variety activated during testing. Ultimately, DOE determined not to restrict active control variety during testing. 87 FR 57264. The test procedure for circulator pumps allows the manufacturer of a circulator pump to does not require a particular control variety to limit application to a particular control variety. Section B.2 of appendix D to subpart Y of 10 CFR part 431.

In the September 2022 TP Final Rule, DOE stated that although the test procedure does not restrict active control variety during testing, whether compliance with a potential future energy conservation standard would be based on a specific control mode (or no controls), or whether certain information related to the control mode used for testing would be required as part of certification, would be addressed in an energy conservation standard rulemaking.

In this NOPR, DOE proposes to require compliance with energy conservation standards for circulator pumps while operated in the least consumptive control mode in which it is capable of operating. Because many circulator pumps equipped with control

[28] In this document, circulator pumps with ''no controls'' are also inclusive of other potential control varieties that are not one of the specifically identified control varieties. *See* section III.D.7 of this document.

modes designed to reduce energy consumption relate to full-speed operating also include the ability to operate at constant-speed, to require testing using a circulator pumps' most consumptive control mode may reduce the ability of rated CEI to characterize the degree of energy savings possible across circulator pump models. Circulator pump basic models equipped with a variety of control modes would receive the same rating as an otherwise identical basic model which could operate only at full speed, even though in practice the former may consume considerably less energy in many applications.

As stated in section III.A.3 of this document, certification requirements, including those related to active control variety, are not being proposed in this NOPR, but may be addressed in a potential future rulemaking.

DOE requests comment regarding circulator pump control variety for the purposes of demonstrating compliance with energy conservation standards.

D. Technological Feasibility

1. General

In each energy conservation standards rulemaking, DOE conducts a screening analysis based on information gathered on all current technology options and prototype designs that could improve the efficiency of the products or equipment that are the subject of the rulemaking. As the first step in such an analysis, DOE develops a list of technology options for consideration in consultation with manufacturers, design engineers, and other interested parties. DOE then determines which of those means for improving efficiency are technologically feasible. DOE considers technologies incorporated in commercially-available products or in working prototypes to be technologically feasible. Sections 6(c)(3)(i) and 7(b)(1) of appendix A to 10 CFR 431.4; 10 CFR part 430, subpart C (''Process Rule'').

After DOE has determined that particular technology options are technologically feasible, it further evaluates each technology option in light of the following additional screening criteria: (1) practicability to manufacture, install, and service; (2) adverse impacts on product utility or availability; (3) adverse impacts on health or safety, and (4) unique-pathway proprietary technologies. 10 CFR 431.4; Sections 6(b)(3)(ii)–(v) and 7(b)(2)–(5) of the Process Rule. Section IV.B of this document discusses the results of the screening analysis for circulator pumps, particularly the designs DOE considered, those it screened out, and those that are the basis for the standards considered in this rulemaking. For further details on the screening analysis for this rulemaking, see chapter 4 of the NOPR technical support document (''TSD'').

2. Maximum Technologically Feasible Levels

When DOE proposes to adopt a new or amended standard for a type or class of covered equipment, it must determine the maximum improvement in energy efficiency or maximum reduction in energy use that is technologically feasible for such product. (42 U.S.C. 6316(a); 42 U.S.C. 6295(p)(1)) Accordingly, in the engineering analysis, DOE determined the maximum technologically feasible (''max-tech'') improvements in energy efficiency for circulator pumps, using the design parameters for the most efficient products available on the market or in working prototypes. The max-tech levels that DOE determined for this rulemaking are described in section IV.C of this proposed rule and in chapter 5 of the NOPR TSD.

E. Energy Savings

1. Determination of Savings

For each trial standard level (''TSL''), DOE projected energy savings from application of the TSL to circulator pumps purchased in the 30-year period that begins in the year of compliance with the proposed standards (2026–2055).[29] The savings are measured over the entire lifetime of circulator pumps purchased in the previous 30-year period. DOE quantified the energy savings attributable to each TSL as the difference in energy consumption between each standards case and the no-new-standards case. The no-new-standards case represents a projection of energy consumption that reflects how the market for equipment would likely evolve in the absence of new energy conservation standards.

DOE used its national impact analysis (''NIA'') spreadsheet model to estimate national energy savings (''NES'') from potential new standards for circulator pumps. The NIA spreadsheet model (described in section IV.H of this document) calculates energy savings in terms of site energy, which is the energy directly consumed by products at the locations where they are used. For electricity, DOE reports NES in terms of primary energy savings, which is the savings in the energy that is used to generate and transmit the site electricity. DOE also calculates NES in terms of FFC energy savings. The FFC metric includes the energy consumed in extracting, processing, and transporting primary fuels (*i.e.,* coal, natural gas, petroleum fuels), and thus presents a more complete picture of the impacts of energy conservation standards.[30] DOE's approach is based on the calculation of an FFC multiplier for each of the energy types used by covered products or equipment. For more information on FFC energy savings, see section IV.H.2 of this document.

2. Significance of Savings

To adopt any new or amended standards for covered equipment, DOE must determine that such action would result in significant energy savings. (42 U.S.C. 6295(o)(3)(B))

The significance of energy savings offered by a new or amended energy conservation standard cannot be determined without knowledge of the specific circumstances surrounding a given rulemaking.[31] For example, some covered products and equipment have most of their energy consumption occur during periods of peak energy demand. The impacts of these products on the energy infrastructure can be more pronounced than products with relatively constant demand. In evaluating the significance of energy savings, DOE considers differences in primary energy and FFC effects for different covered products and equipment when determining whether energy savings are significant. Primary energy and FFC effects include the energy consumed in electricity production (depending on load shape), in distribution and transmission, and in extracting, processing, and transporting primary fuels (*i.e.,* coal, natural gas, petroleum fuels), and thus present a more complete picture of the impacts of energy conservation standards.

Accordingly, DOE evaluates the significance of energy savings on a case-by-case basis. As mentioned previously, the proposed standards are projected to result in estimated national FFC energy savings of 0.45 quads, the equivalent of the electricity use of 4.4 million homes

[29] Typically, each TSL is composed of specific efficiency levels for each equipment class. In the case of circulator pumps, because there is only one equipment class, each TSL is the same as its corresponding efficiency level. DOE conducted a sensitivity analysis that considers impacts for products shipped in a 9-year period.

[30] The FFC metric is discussed in DOE's statement of policy and notice of policy amendment. 76 FR 51282 (August 18, 2011), as amended at 77 FR 49701 (August 17, 2012).

[31] The numeric threshold for determining the significance of energy savings established in a final rule published on February 14, 2020 (85 FR 8626, 8670), was subsequently eliminated in a final rule published on December 13, 2021 (86 FR 70892).

in one year. DOE has initially determined the energy savings from the proposed standard levels are ''significant'' within the meaning of 42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(3)(B).

F. Economic Justification

1. Specific Criteria

As noted previously, EPCA provides seven factors to be evaluated in determining whether a potential energy conservation standard is economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(I)–(VII)) The following sections discuss how DOE has addressed each of those seven factors in this rulemaking.

a. Economic Impact on Manufacturers and Consumers

In determining the impacts of a potential standard on manufacturers, DOE conducts an MIA, as discussed in section IV.J of this document. DOE first uses an annual cash-flow approach to determine the quantitative impacts. This step includes both a short-term assessment—based on the cost and capital requirements during the period between when a regulation is issued and when entities must comply with the regulation—and a long-term assessment over a 30-year period. The industry-wide impacts analyzed include (1) INPV, which values the industry on the basis of expected future cash flows, (2) cash flows by year, (3) changes in revenue and income, and (4) other measures of impact, as appropriate. Second, DOE analyzes and reports the impacts on different types of manufacturers, including impacts on small manufacturers. Third, DOE considers the impact of standards on domestic manufacturer employment and manufacturing capacity, as well as the potential for standards to result in plant closures and loss of capital investment. Finally, DOE takes into account cumulative impacts of various DOE regulations and other regulatory requirements on manufacturers.

For individual consumers, measures of economic impact include the changes in LCC and PBP associated with new or amended standards. These measures are discussed further in the following section. For consumers in the aggregate, DOE also calculates the national net present value of the consumer costs and benefits expected to result from particular standards. DOE also evaluates the impacts of potential standards on identifiable subgroups of consumers that may be affected disproportionately by a standard.

b. Savings in Operating Costs Compared To Increase in Price (LCC and PBP)

EPCA requires DOE to consider the savings in operating costs throughout the estimated average life of the covered equipment in the type (or class) compared to any increase in the price of, or in the initial charges for, or maintenance expenses of, the covered equipment that are likely to result from a standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(II)) DOE conducts this comparison in its LCC and PBP analysis.

The LCC is the sum of the purchase price of a product (including its installation) and the operating expense (including energy, maintenance, and repair expenditures) discounted over the lifetime of the product. The LCC analysis requires a variety of inputs, such as product prices, product energy consumption, energy prices, maintenance and repair costs, product lifetime, and discount rates appropriate for consumers. To account for uncertainty and variability in specific inputs, such as product lifetime and discount rate, DOE uses a distribution of values, with probabilities attached to each value.

The PBP is the estimated amount of time (in years) it takes consumers to recover the increased purchase cost (including installation) of a more-efficient product through lower operating costs. DOE calculates the PBP by dividing the change in purchase cost due to a more-stringent standard by the change in annual operating cost for the year that standards are assumed to take effect.

For its LCC and PBP analysis, DOE assumes that consumers will purchase the covered equipment in the first year of compliance with new or amended standards. The LCC savings for the considered efficiency levels are calculated relative to the case that reflects projected market trends in the absence of new or amended standards. DOE's LCC and PBP analysis is discussed in further detail in section IV.F of this document.

c. Energy Savings

Although significant conservation of energy is a separate statutory requirement for adopting an energy conservation standard, EPCA requires DOE, in determining the economic justification of a standard, to consider the total projected energy savings that are expected to result directly from the standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(III)) As discussed in section III.E, DOE uses the NIA spreadsheet models to project national energy savings.

d. Lessening of Utility or Performance of Products

In establishing product classes and in evaluating design options and the impact of potential standard levels, DOE evaluates potential standards that would not lessen the utility or performance of the considered products. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(IV)) Based on data available to DOE, the standards proposed in this document would not reduce the utility or performance of the products under consideration in this rulemaking.

e. Impact of Any Lessening of Competition

EPCA directs DOE to consider the impact of any lessening of competition, as determined in writing by the Attorney General, that is likely to result from a proposed standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(V)) It also directs the Attorney General to determine the impact, if any, of any lessening of competition likely to result from a proposed standard and to transmit such determination to the Secretary within 60 days of the publication of a proposed rule, together with an analysis of the nature and extent of the impact. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(ii)) DOE will transmit a copy of this proposed rule to the Attorney General with a request that the Department of Justice (''DOJ'') provide its determination on this issue. DOE will publish and respond to the Attorney General's determination in the final rule. DOE invites comment from the public regarding the competitive impacts that are likely to result from this proposed rule. In addition, stakeholders may also provide comments separately to DOJ regarding these potential impacts. See the **ADDRESSES** section for information to send comments to DOJ.

f. Need for National Energy Conservation

DOE also considers the need for national energy and water conservation in determining whether a new or amended standard is economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(VI)) The energy savings from the proposed standards are likely to provide improvements to the security and reliability of the Nation's energy system. Reductions in the demand for electricity also may result in reduced costs for maintaining the reliability of the Nation's electricity system. DOE conducts a utility impact analysis to estimate how standards may affect the Nation's needed power generation capacity, as discussed in section IV.M of this document.

DOE maintains that environmental and public health benefits associated with the more efficient use of energy are important to take into account when considering the need for national energy conservation. The proposed standards are likely to result in environmental benefits in the form of reduced emissions of air pollutants and greenhouse gases (''GHGs'') associated with energy production and use. DOE conducts an emissions analysis to estimate how potential standards may affect these emissions, as discussed in section IV.K; the estimated emissions impacts are reported in section V.B.6 of this document. DOE also estimates the economic value of emissions reductions resulting from the considered TSLs, as discussed in section IV.L of this document.

g. Other Factors

In determining whether an energy conservation standard is economically justified, DOE may consider any other factors that the Secretary deems to be relevant. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)(VII)) To the extent DOE identifies any relevant information regarding economic justification that does not fit into the other categories described previously, DOE could consider such information under ''other factors.''

2. Rebuttable Presumption

EPCA creates a rebuttable presumption that an energy conservation standard is economically justified if the additional cost to the equipment that meets the standard is less than three times the value of the first year's energy savings resulting from the standard, as calculated under the applicable DOE test procedure. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(iii)). DOE's LCC and PBP analyses generate values used to calculate the effects that proposed energy conservation standards would have on the payback period for consumers. These analyses include, but are not limited to, the 3-year payback period contemplated under the rebuttable-presumption test. In addition, DOE routinely conducts an economic analysis that considers the full range of impacts to consumers, manufacturers, the Nation, and the environment, as required under 42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i). The results of this analysis serve as the basis for DOE's evaluation of the economic justification for a potential standard level (thereby supporting or rebutting the results of any preliminary determination of economic justification). The rebuttable presumption payback calculation is discussed in section V.B.1 of this proposed rule.

G. Effective Date

EPCA does not prescribe a compliance lead time for energy conservation standards for pumps, *i.e.,* the number of years between the date of publication of a final standards rule and the date on which manufacturers must comply with the new standard. And, while 42 U.S.C. 62959(m)(4)(B) states that manufacturers shall not be required to apply new standards to a product with respect to which other new standards have been required during the prior 6-year period, the standards proposed in this document would be the first energy conservation standards for circulator pumps. The November 2016 CPWG Recommendations specified a compliance date of four years following publication of the final rule.

Two parties commented in response to the May 2021 RFI regarding effective date of potential energy conservation standards.

Grundfos recommended a 2-year compliance date due to the effort already made by the circulator pump industry to test circulator pumps. (Grundfos, No.113, at p. 1) NEEA, which recommended a 3-year compliance date, also mentioned the testing efforts and experience made by the circulator pump industry to test circulator pumps and argued that the industry is mature and capable of meeting the standard level recommended by the CPWG (which would have gone into effect by the end of 2021) at an earlier date. (NEEA, No. 115, at p. 3)

DOE agrees with commenters' arguments that the circulator pump industry is now more mature compared to 2016, and in this NOPR is proposing a 2-year compliance date for energy conservation standards. DOE is requesting comment on this proposal and notes that, depending on stakeholder comment, DOE may also consider a 3-year compliance date in the final rule.[32]

IV. Methodology and Discussion of Related Comments

This section addresses the analyses DOE has performed for this rulemaking with regard to circulator pumps. Separate subsections address each component of DOE's analyses.

DOE used several analytical tools to estimate the impact of the standards proposed in this document. The first tool is a spreadsheet that calculates the LCC savings and PBP of potential amended or new energy conservation standards. The national impacts analysis uses a second spreadsheet set that provides shipments projections and calculates national energy savings and net present value of total consumer costs and savings expected to result from potential energy conservation standards. DOE uses the third spreadsheet tool, the Government Regulatory Impact Model (''GRIM''), to assess manufacturer impacts of potential standards. These three spreadsheet tools are available on the DOE website for this rulemaking: *www1.eere.energy.gov/buildings/appliance_standards/standards.aspx?productid=66.* Additionally, DOE used output from the latest version of the Energy Information Administration's (''EIA's'') *Annual Energy Outlook* (''*AEO*''), a widely known energy projection for the United States, for the emissions and utility impact analyses.

A. Market and Technology Assessment

DOE develops information in the market and technology assessment that provides an overall picture of the market for the products concerned, including the purpose of the products, the industry structure, manufacturers, market characteristics, and technologies used in the products. This activity includes both quantitative and qualitative assessments, based primarily on publicly available information. The subjects addressed in the market and technology assessment for this rulemaking include (1) a determination of the scope of the rulemaking and product classes, (2) manufacturers and industry structure, (3) existing efficiency programs, (4) shipments information, (5) market and industry trends; and (6) technologies or design options that could improve the energy efficiency of circulator pumps. The key findings of DOE's market assessment are summarized in the following sections. See chapter 3 of the NOPR TSD for further discussion of the market and technology assessment.

1. Scope of Coverage and Equipment Classes

a. Scope

As stated in section III.B, DOE is proposing to align the scope of these proposed energy conservation standards with that of the circulator pumps test procedure. 87 FR 57264. In that notice, DOE finalized the scope of the circulator pumps test procedure such that it applies to circulator pumps that are

[32] DOE notes that, due to projected market trends, a change in the rulemaking's compliance date may lead to a small but non-negligible change in consumer and manufacturer benefits or impacts.

clean water pumps, including circulators-less-volute and on-demand circulator pumps, and excluding header pumps and submersible pumps. That scope is consistent with the recommendations of the CPWG (Docket No. EERE–2016–BT–STD–0004, No. 58).

In response to the May 2021 RFI, HI and Grundfos stated that they believed all circulator pumps are included in the scope defined by the CPWG in the term sheets. (HI, No. 112 at p. 8; Grundfos, No. 113 at p. 7).

DOE is proposing to apply energy conservation standards to all circulator pumps included in the CWPG recommendations, which excluded submersible pumps and header pumps. (Docket No. EERE–2016–BT–STD–0004, No. 58). The September 2022 TP Final Rule also excluded submersible pumps and header pumps. Any future evaluation of energy conservation standards would require a corresponding test procedure.

DOE requests comment regarding the proposed scope of energy conservation standards for circulator pumps.

Equipment Diagrams

In general, DOE establishes written definitions to designate which products or equipment fall within the scope of a test procedure or energy conservation standard. In the specific case of circulator pumps, certain scope-related definitions were adopted by the September 2022 TP Final Rule and codified at 10 CFR 431.462.

In response to the May 2021 RFI, China requested that DOE add schematic diagrams for each product in addition to the text definition to avoid misunderstandings (China, No. 111 at p. 1).

The definitions which serve to distinguish various varieties of circulator pumps were adopted nearly unchanged from those recommended by the CPWG at meeting 2. (Docket No. EERE–2016–BT–STD–0004–0021, p. 22) 10 CFR 431.462. CPWG membership included five manufacturers of circulator pumps, a trade association representing the US hydraulic industry, a trade association representing plumbing, heating, and cooling contractors, and other manufacturers of equipment which either use or are used by circulator pumps as components.

Given the strong representation of entities with deep experience in circulator pump design and for whom definitional ambiguity could be burdensome, it is reasonable to expect the CPWG-proposed definitions were viewed at least at the time of their recommendation as sufficiently clear.

Additionally, the development of diagrams which effectively serve as parallel equipment definitions creates the possibility of introducing confusion insofar as interpretations of such diagrams differ from those of the corresponding written definitions.

In view of the absence of identification of a specific definitional ambiguity and of the potential resulting confusion from a diagram that could be interpreted differently from corresponding written definitions at 10 CFR 431.462, DOE is not proposing to establish equipment diagrams in this NOPR.

DOE requests comment regarding the present circulator pump-related definitions, and in particular whether any clarifications are warranted.

b. Equipment Classes

When evaluating and establishing energy conservation standards, DOE may divide covered equipment into equipment classes by the type of energy used, or by capacity or other performance-related features that justify a different standard. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q)) In making a determination whether capacity or another performance-related feature justifies a different standard, DOE must consider such factors as the utility of the feature to the consumer and other factors DOE deems appropriate. (*Id.*)

For circulator pumps, there are no current energy conservation standards and, thus, no preexisting equipment classes. However, the November 2016 Term Sheets contained a recommendation related to establishing equipment classes for circulator pumps. Specifically, ‘‘Recommendation #1’’ of the November 2016 CPWG Recommendations suggests grouping all circulator pumps into a single equipment class, though with numerical energy conservation standard values that vary as a function of hydraulic output power. (Docket No. EERE–2016–BT–STD–0004, No. 98 Recommendation #1 at p. 1)

In the May 2021 RFI, DOE requested comment regarding the CPWG recommendation to include all circulator pumps within a single equipment class.

HI agreed with the CPWG that circulator pumps should be evaluated within a single equipment class and no design options are known that are incompatible or that would necessitate an additional equipment class. (HI, No. 112 at p. 8). Grundfos also agreed with the CPWG recommendation of a single circulator pump class as long as C-values are defined based on motor size. (Grundfos, No. 113 at p. 6).

As stated in section III.B.1, circulator pumps may be offered in wet- or dry-rotor configurations, and if dry-rotor, in either close-coupled or mechanically coupled construction. Minor differences in attributes may exist across configurations. For example, during interviews with manufacturers DOE learned that wet-rotor pumps tended to be quieter, whereas dry-rotor pumps may be easier to service. In general, however, each respective pump variety serves similar applications. Similarly, data provided to DOE as part of the confidential submission process indicates that each variety may reach similar efficiency levels when operated with similar motor technology. Accordingly, no apparent basis exists to warrant establishing separate equipment classes by circulator pump configuration.

One additional salient design attribute of circulator pumps is housing material. Generally, circulator pumps are built using cast iron, bronze, or stainless-steel housing. Bronze and stainless steel (sometimes discussed collectively with the descriptor ‘‘nonferrous’’) carry greater corrosion resistance and are thus suitable for use in applications in which they will be exposed to corrosive elements. Typically, corrosion resistance is most important in ‘‘open loop’’ applications in which new water is constantly being replaced.

By contrast, cast iron (sometimes described as ‘‘ferrous’’ to distinguish from the ‘‘nonferrous’’ descriptor applied to bronze and stainless steel) pump housing is less resistant to corrosion than bronze or stainless steel, and as a result is generally limited to ‘‘closed loop’’ applications in which the same water remains in the hydraulic circuit, in which it will eventually become deionized and less able to corrode metallic elements of circulator pumps. Cast iron is generally less expensive to manufacture than bronze or stainless steel, and as a result bronze or stainless-steel circulator pumps are less commonly selected by consumers for applications which do not strictly require them.

Although a difference in utility exists across circulator pump housing materials, no such difference exists in ability to reach higher efficiencies. All housing materials are able to reach all efficiency levels analyzed in this NOPR. Accordingly, no apparent basis exists to warrant establishing separate equipment classes by circulator pump housing material.

DOE requests comment regarding the proposal to analyze all circulator pumps within a single equipment class.

On-Demand Circulator Pumps

On-demand circulator pumps respond to actions of the user, rather than other factors such as pressure, temperature, or time. In the September 2022 TP Final Rule, DOE adopted the following definition for on-demand circulator pumps, which is consistent with that recommended by the CPWG (Docket No. EERE–2016–BT–STD–0004, No. 98 Recommendation 4 at p. 5):

On-demand circulator pump means a circulator pump that is distributed in commerce with an integral control that:

• Initiates water circulation based on receiving a signal from the action of a user [of a fixture or appliance] or sensing the presence of a user of a fixture and cannot initiate water circulation based on other inputs, such as water temperature or a pre-set schedule.

• Automatically terminates water circulation once hot water has reached the pump or desired fixture.

• Does not allow the pump to operate when the temperature in the pipe exceeds 104 °F or for more than 5 minutes continuously.

10 CFR 431.462.

In response to the May 2021 RFI, HI commented that greater energy savings could be achieved through demand-based variable speed controls than would arise from redesign of a circulator pump's hydraulic components. (HI, No. 112 at p. 7). DOE interprets this comment to refer to other controls than user-reacting, both because of the specific naming of variable-speed (which is not necessary for user-triggered controls) and because of the context in which the comment was made. Nonetheless, it is logically possible that on-demand circulator pumps may indeed save energy relative to non-on-demand circulator pumps in certain applications.

The TP final rule (87 FR 57264) responded to a number of comments received in response to the December 2021 TP NOPR, which were discussed therein. Several commenters encouraged DOE to develop an adjustment to the CEI metric that accounted for the potential of on-demand circulator pumps to save energy in certain contexts. (EERE–2016–BT–TP–0033, No. 10 at p. 5; EERE–2016–BT–TP–0033, No. 11 at pp. 4–5). Other commenters did not support an adjusted CEI metric for on-demand circulator pumps in the test procedure final rule, but recommended evaluation of such in a potential future rulemaking. (Docket No. EERE–2016–BT–TP–0033, No. 9 at p.3; EERE–2016–BT–TP–0033, No. 7 at p. 1).

DOE ultimately did not adopt any modification to the CEI metric for on-demand circulator pumps in the final rule but stated that it would consider the appropriate scope and product categories for standards for on-demand circulator pumps in a separate energy conservation rulemaking.

As stated in section III.B, DOE is proposing to align the scope of energy conservation standards for circulator pumps consistently with that of the test procedure for circulator pumps, which includes on-demand circulator pumps. 87 FR 57264.

In developing the equipment class structure, DOE is directed to consider, among other factors, performance-related features that justify a different standard and the utility of such features to the consumer. (42 U.S.C. 6316(a); 42 U.S.C. 6295(q)) In the specific case of on-demand circulator pumps, the primary distinguishing feature (*i.e.,* ability to react to user action or presence) is not obviously performance related. It does not impede the ability of circulator pumps to reach the same performance levels as any other circulator pumps. On that basis, DOE is proposing not to establish a separate equipment class for on-demand circulator pumps in this NOPR.

It remains true, as observed by commenters, that in certain applications on-demand circulator pumps may save energy relative to non-on-demand circulator pumps through reduced aggregate operating durations. Operating duration of on-demand circulator pumps is considered in the energy use analysis, which is described in section IV.E.3 of this document.

DOE requests comment on its proposal not to establish a separate equipment class for on-demand circulator pumps.

2. Technology Options

In the preliminary market analysis and technology assessment, DOE identified 3 technology options that would be expected to improve the efficiency of circulator pumps, as measured by the DOE test procedure:

• Improved hydraulic design
• More efficient motors
• Increase number of motor speeds

Chapter 3 of the NOPR TSD details each of these technology options. The following sections summarize the stakeholder comments on these technology option by variety.

a. Hydraulic Design

The performance characteristics of a pump, such as flow, head, and efficiency, are influenced by the pump's hydraulic design. For purposes of DOE's analysis, ''hydraulic design'' is a broad term used to describe the system design of the wetted components of a pump. Although hydraulic design focuses on the specific hydraulic characteristics of the impeller and the volute/casing, it also includes design choices related to bearings, seals, and other ancillary components.

Impeller and volute/casing geometries, clearances, and associated components can be redesigned to a higher efficiency (at the same flow and head) using a combination of techniques including historical best practices and modern computer-aided design (CAD) and analysis methods. The wide availability of modern CAD packages and techniques now enables pump designers to reach designs with improved vane shapes, flow paths, and cutwater designs more quickly, all of which work to improve the efficiency of the pump as a whole.

In response to the May 2021 RFI, Grundfos stated there are only small efficiency gains to be gained through hydraulic design. (Grundfos, No. 113 at p. 6). HI responded to the May 2021 RFI explaining the savings gained through improved hydraulic design is not sufficient to meet EPCA requirements. Additionally, the energy savings does not offset the cost of modifying the hydraulic design. (HI, No. 112 at p. 7)

b. More Efficient Motors

Different constructions of motors have different achievable efficiencies. Two general motor constructions are present in the circulator pump market: induction motors, and ECMs. Induction motors include both single-phase and three-phase configurations. Single-phase induction motors may be further differentiated and include split phase, capacitor-start induction-run (CSIR), capacitor-start capacitor-run (CSCR), and PSC motors. HI stated that the majority of circulator pumps currently available on the market use PSC motors, which is a variety of induction motor (HI, No. 112 at p. 11). DOE confirmed using confidentially submitted manufacturer data that induction motor circulator pumps account for the majority of the circulator pump market.

The efficiency of an induction motor can be increased by redesigning the motor to reduce slip losses between the rotor and stator components, as well as reducing mechanical losses at seals and bearings. ECMs are generally more efficient than induction motors because their construction minimizes slip losses between the rotor and stator components. Unlike induction motors, however, ECMs require an electronic drive to function. This electronic drive consumes electricity, and variations in drive losses and mechanical designs lead to a range of ECM efficiencies. In response to the May 2021 RFI HI and NEEA stated ECMs are experiencing a slow growth in the market, with faster growth in areas where there are utility incentives. (HI, No. 112 at p. 10; NEEA, No. 115 at p. 4).

The performance standard for this rule is based upon wire-to-water efficiency, which is defined as the hydraulic output power of a circulator pump divided by its line input power and is expressed as a percentage. The achievable wire-to-water efficiency of circulator pumps is influenced by both hydraulic efficiency and motor efficiency. As part of the engineering analysis (Section IV.C), DOE assessed the range of attainable wire-to-water efficiencies for circulator pumps with induction motors, and those with ECMs, over a range of hydraulic power outputs. Because circulator pump efficiency is measured on a wire-to-water basis, it is difficult to fully separate differences due to motor efficiency from those due to hydraulic efficiency. In response to the May 2021 RFI, HI stated that improved motor efficiency and demand-based variable speed controls can achieve greater energy savings than from improved hydraulic efficiency. (HI, No. 112 at p. 7). However, in redesigning a pump model to meet today's proposed standard, manufacturers could consider both hydraulic efficiency and motor efficiency.

Higher motor capacities are generally required for higher hydraulic power outputs, and as motor capacity increases, the attainable efficiency of the motor at full load also increases. Higher horsepower motors also operate close to their peak efficiency for a wider range of loading conditions.[33]

Circulator pump manufacturers either manufacture motors in-house or purchase complete or partial motors from motor manufacturers and/or distributors. Manufacturers may select an entirely different motor or redesign an existing motor in order to improve a pump's motor efficiency.

c. Speed Reduction

Circulator pumps with the variable speed capability can reduce their energy consumption by reducing pump speed to match load requirements. As discussed in the September 2022 TP Final Rule, the CER metric is a weighted average of input powers at each test point relative to BEP flow. The circulator pump test procedure allows CER values for multi- and variable-speed circulator pumps to be calculated as the weighted average of input powers at full speed BEP flow, and reduced speed at flow points less than BEP; CER for single-speed circulator pumps is calculated based only on input power at full speed. 10 CFR 431.464(c)(2). Due to pump affinity laws, variable-speed circulator pumps will achieve reduced power consumption at flow points less than BEP by reducing their rotational speed to more closely match required system head. As such, the CER metric grants benefits on circulator pumps capable of variable speed operation.

Specifically, pump affinity laws describe the relationship of pump operating speed, flow rate, head, and hydraulic power. According to the affinity laws, flow varies proportionally with the pump's rotational speed, as described in equation (6). The affinity laws also establish that pump total head is proportional to speed squared, as described in equation (7), and pump hydraulic power is proportional to speed cubed, as described in equation (8)

$$\frac{Q_1}{Q_2} = \frac{N_1}{N_2} \qquad (6)$$

$$\frac{H_1}{H_2} = \left(\frac{N_1}{N_2}\right)^2 \qquad (7)$$

$$\frac{P_1}{P_2} = \left(\frac{N_1}{N_2}\right)^3 \qquad (8)$$

Where:

Q_1 and Q_2 = volumetric flow rate at two operating points
H_1 and H_2 = pump total head at two operating points
N_1 and N_2 = pump rotational speed at two operating points
P_1 and P_2 = pump hydraulic power at two operating points

This means that a pump operating at half speed will provide one half of the pump's full-speed flow and one eighth of the pump's full-speed power.[34] However, pump affinity laws do not account for changes in hydraulic and motor efficiency that may occur as a pump's rotational speed is reduced. Typically, hydraulic efficiency and motor efficiency will be reduced at lower operating speeds. Consequently, at reduced speeds, power consumption is not reduced as drastically as hydraulic output power. Even so, the efficiency losses at low-speed operation are typically outweighed by the

[33] U.S. DOE Building Technologies Office. *Energy Savings Potential and Opportunities for High-Efficiency Electric Motors in Residential and Commercial Equipment.* December 2013. Prepared for the DOE by Navigant Consulting. pp. 4. Available at *https://energy.gov/sites/prod/files/2014/02/f8/Motor%20Energy%20Savings%20Potential%20Report%202013-12-4.pdf DFR.*

[34] A discussion of reduced-speed pump dynamics is available at *www.regulations.gov/document?D=EERE-2015-BT-STD-0008-0099.*

exponential reduction in hydraulic output power at low-speed operation; this results in a lower input power at low-speed operation at flow points lower than BEP.

Circulator pump speed controls may be discrete or continuous, as well as manual or automatic. Circulator pumps with discrete speed controls vary the circulator pump's rotational speed in a stepwise manner. Discrete controls are found mostly on circulator pumps with induction motors and have several speed settings that are can be used to allow contractors greater installation flexibility with a single circulator pump model. For these circulator pumps, the speed is set manually with a dial or buttons by the installer or user and operate at a constant speed once the installation is complete.

Circulator pumps equipped with automatic speed controls can adjust the circulator pump's rotational speed based on a signal from differential pressure or temperature sensors, or an external input signal from a boiler. The variable frequency drives required for ECMs makes them fairly amenable to the addition of variable speed control logic; currently the vast majority of circulator pumps with automatic continuously variable speed controls also have ECM motors. However, some circulator pump models with induction motors also come equipped with automatic continuous variable speed controls. While automatic controls can reduce energy consumption by allowing circulator pump speed to dynamically respond to changes in system conditions, these controls can also reduce energy consumption by reducing speed to a single, constant value that is optimized based on system head at the required flow point. Automatic controls can be broadly categorized into two groups: pressure-based controls, and temperature-based controls.

Pressure-based controls vary the circulator pump speed based on changes in the system pressure. These pressure changes are typically induced by a thermostatically controlled zone valve that monitors the space temperature in different zones and calls for heat (*i.e.,* opens the valve) when the space/zone temperature is below the set-point, similar to a thermostat. In this type of control, a pressure sensor internal to the circulator pump determines the amount of pressure in the system and adjusts the circulator pump speed to achieve the desired system pressure.

Temperature-based controls monitor the supply and return temperature to the circulator pump and modulates the circulator pump's speed to maintain a fixed temperature drop across the system. Circulator pumps with temperature-based controls are able to serve the heat loads of a conditioned space at a lower speed, and therefore lower input power, than the differential pressure control because it can account for the differential temperature between the space and supplied hot water, delivering a constant BTU/hr load to the space when less heat is needed even in a given zone or zones.

In response to the 2021 RFI, Grundfos stated the ability to reduce speed is the most important criteria for achieving higher efficiency in circulator products. (Grundfos, No. 113 at p. 6). Reducing performance according to system need can achieve 50–60% savings (*Id.*). Grundfos explains further that the ability to run at reduced speeds is the costliest solution, but the larger savings can offset the higher costs and to help offset conversion to this technology (*Id.*). Understanding the lifetime energy saving compared to the higher initial cost is important for market adoption (*Id.*). The largest concern for the implementation is that optimization of the control mode can be problematic for an end user and requires higher level knowledge to gain maximum efficiencies (*Id.*). NEEA responded with data showing that currently, fewer than one-fifth of circulator pumps are equipped with speed control technology. (NEEA, No. 115 at p. 6). This shows the significant potential the market has for energy savings by using more pumps with the ability to operate at reduced speeds.

In the May 2021 RFI, DOE requested comment on increasing circulator pump efficiency using improved hydraulic design, more efficient motors, and/or increased number of motor speeds.

HI responded stating they are not aware of other design option that increase efficiency. (HI, No. 112 at p. 7). HI stated that the market is focused on improved motors and demand-based variable speed control and does not believe any other design changes, so far discovered, would occur (*Id.*). HI believes ECM circulator pumps with variable speed controls represent the maximum technology option. (*Id.*). The initial cost for these techniques is higher to consumers due to the higher cost of the efficient motor and incorporation of controls; however, the total life cycle cost to the consumer should be lower due to energy savings (*Id.*). The addition of ECMs and controls adds complexity to manufacturing due to scarcity of materials, reliance on non-domestic sources, automated assembly, and special tooling. Further complexity associated with ECMs are disposal and recycling programs (*Id.*). HI recommends DOE conduct manufacturer interviews to get additional updated information such as costs for design options to update the previous data request from 2016 (HI, No. 112 at p. 8). DOE received this data in the 2022 manufacturer interviews.

Grundfos responded stating the technology described is a fair description of the current state of the market. (Grundfos, No. 113 at p. 6). Grundfos explained that the most advanced products in the market are approaching the maximum possible efficiency values and any further energy use reductions would only be realized through more efficient system designs (piping/valves/etc.) and adoption of more efficient system interaction (interconnectivity to appliances, smart homes, etc.) (*Id.*).

In the May 2021 RFI, DOE requested comment on whether certain design options may not be applicable to specific equipment classes. Grundfos responded stating it does not see any limitations in design options for equipment classes. (Grundfos, No. 113 at p. 8). HI responded stating that no design options are known that are incompatible or that would necessitate an additional equipment class. (HI, No. 112 at p. 8).

Based on comments, DOE concludes that the technology options identified are sufficient to conduct the engineering analysis, which is discussed in section IV.C.

B. Screening Analysis

DOE uses the following five screening criteria to determine which technology options are suitable for further consideration in an energy conservation standards rulemaking:

(1) *Technological feasibility.* Technologies that are not incorporated in commercial products or in working prototypes will not be considered further.

(2) *Practicability to manufacture, install, and service.* If it is determined that mass production and reliable installation and servicing of a technology in commercial products could not be achieved on the scale necessary to serve the relevant market at the time of the projected compliance date of the standard, then that technology will not be considered further.

(3) *Impacts on product utility or product availability.* If it is determined that a technology would have a significant adverse impact on the utility of the product for significant subgroups of consumers or would result in the unavailability of any covered equipment type with performance characteristics

(including reliability), features, sizes, capacities, and volumes that are substantially the same as products generally available in the United States at the time, it will not be considered further.

(4) *Adverse impacts on health or safety.* If it is determined that a technology would have significant adverse impacts on health or safety, it will not be considered further.

(5) *Unique-Pathway Proprietary Technologies.* If a design option utilizes proprietary technology that represents a unique pathway to achieving a given efficiency level, that technology will not be considered further due to the potential for monopolistic concerns.

10 CFR 431.4; 10 CFR part 430, subpart C, appendix A, sections 6(b)(3) and 7(b).

In summary, if DOE determines that a technology, or a combination of technologies, fails to meet one or more of the listed five criteria, it will be excluded from further consideration in the engineering analysis. The reasons for eliminating any technology are discussed in the following sections.

The subsequent sections include comments from interested parties pertinent to the screening criteria, DOE's evaluation of each technology option against the screening analysis criteria, and whether DOE determined that a technology option should be excluded (''screened out'') based on the screening criteria.

1. Screened-Out Technologies

In the May 2021 RFI, DOE requested comment regarding the screening criteria and on what impact they may have on currently identified and potential future possible technology options for circulator pumps. 86 FR 24516, 24530 (May 26, 2021).

In response, HI commented that ECMs and controls could potentially become a problem due to scarcity of necessary component materials, reliance on foreign sources, and the degree of automation and specialized tooling involved in the manufacture of ECMs. (HI, No. 112 at p. 7)

DOE interprets HI's comment to be discussing a hypothetical future scenario, and not to be stating that ECMs are unavailable today. Accordingly, ECMs have been retained as a design option for the analysis of this NOPR. DOE will monitor the market for circulator pumps with ECMs and consider removing ECMs as a design option in a future revision to the analysis if availability declines to the degree that circulator pump manufacturers are unable to obtain them, or unable to obtain them at a price level that would create a positive estimated economic proposition for purchasers of ECM-equipped circulator pumps.

DOE requests comment regarding the current and anticipated forward availability of ECMs and components necessary for their manufacture.

2. Remaining Technologies

Through a review of each technology, DOE tentatively concludes that all the other identified technologies listed in section IV.A.2 met all five screening criteria to be examined further as design options in DOE's NOPR analysis. In summary, DOE did not screen out the following technology options:

- Improved hydraulic design
- More efficient motors
- Increase number of motor speeds

DOE has initially determined that these technology options are technologically feasible because they are being used or have previously been used in commercially-available products or working prototypes. DOE also finds that all of the remaining technology options meet the other screening criteria (*i.e.,* practicable to manufacture, install, and service and do not result in adverse impacts on consumer utility, product availability, health, or safety, unique-pathway proprietary technologies). For additional details, see chapter 4 of the NOPR TSD.

C. Engineering Analysis

The purpose of the engineering analysis is to establish the relationship between the efficiency and cost of circulator pumps. There are two elements to consider in the engineering analysis; the selection of efficiency levels to analyze (*i.e.,* the ''efficiency analysis'') and the determination of product cost at each efficiency level (*i.e.,* the ''cost analysis''). In determining the performance of higher-efficiency circulator pumps, DOE considers technologies and design option combinations not eliminated by the screening analysis. For each circulator pump class, DOE estimates the baseline cost, as well as the incremental cost for the circulator pump at efficiency levels above the baseline. The output of the engineering analysis is a set of cost-efficiency ''curves'' that are used in downstream analyses (*i.e.,* the LCC and PBP analyses and the NIA).

1. Representative Equipment

To assess MPC-efficiency relationships for all circulator pumps available on the market, DOE selected a set of representative units to analyze. These representative units exemplify capacities and hydraulic characteristics typical of circulator pumps currently found on the market. In general, to determine representative capacities and hydraulic characteristics, DOE analyzed the distribution of all available models and/or shipments and discussed its findings with the CPWG. The analysis focused on single speed induction motors as they represent the bulk of the baseline of the market.

To start the selection process, nominal horsepower targets based on CPWG feedback of 1/40, 1/25, 1/12,1/6, and 1 HP were selected for representative units (Docket No. EERE–2016–BT–STD–0004–0061, p. 9). At each horsepower target, pump curves were constructed from manufacturer data. Near identical pump curves were consolidated into single curves and curves that represent circulator pumps with low shipments were filtered out to remove the impact of low-selling pumps. These high sales consolidated pump curves were then grouped with similar curves to form clusters of similar circulator pumps. A representative curve was then constructed from this cluster of pumps by using the mean flow and head at each test point. Eight of these curves were constructed to form the eight representative units used in further analyses.

a. Circulator Pump Varieties

Circulator pumps varieties are used to classify different pumps in industry. Wet rotor circulator pump are commonly referred to as CP1, dry rotor, two-piece circulator pumps are commonly referred to as CP2, and dry rotor, three-piece circulator pumps are commonly referred to as CP3. The distinction of circulator varieties does not have a large impact on performance with all circulator pump varieties being capable of achieving any particular performance curve. Due to the performance similarities, the groups of pump curves used to generate representative units contain a mix of all three circulator varieties. Although DOE analyzed CP1, CP2, and CP3 circulator varieties as a single equipment class, representative units were selected such that all circulator varieties were captured in the analysis.

The parameters of each of the representative units used in this analysis are provided in Table IV.1.

TABLE IV.1—REPRESENTATIVE UNIT PARAMETERS

Representative unit	Nominal power (hp)	Flow at BEP (GPM)	Head at BEP (ft)	Phydro at BEP (hp)	Variety
1	1/40	3.073	3.043	0.002	CP1.
2	1/40	5.759	6.628	0.010	CP1.
3	1/25	10.065	9.282	0.024	CP1.
4	1/25	10.525	6.064	0.016	CP1.
5	1/12	17.941	6.510	0.030	CP1, CP2, CP3.
6	1/6	19.521	20.254	0.100	CP1, CP2, CP3.
7	1/6	36.531	10.601	0.098	CP1, CP2, CP3.
8	1	61.200	36.782	0.569	CP1, CP3.

2. Efficiency Analysis

DOE typically uses one of two approaches to develop energy efficiency levels for the engineering analysis: (1) relying on observed efficiency levels in the market (*i.e.,* the efficiency-level approach), or (2) determining the incremental efficiency improvements associated with incorporating specific design options to a baseline model (*i.e.,* the design-option approach). Using the efficiency-level approach, the efficiency levels established for the analysis are determined based on the market distribution of existing products (in other words, based on the range of efficiencies and efficiency level ''clusters'' that already exist on the market). Using the design option approach, the efficiency levels established for the analysis are determined through detailed engineering calculations and/or computer simulations of the efficiency improvements from implementing specific design options that have been identified in the technology assessment. DOE may also rely on a combination of these two approaches. For example, the efficiency-level approach (based on actual products on the market) may be extended using the design option approach to ''gap fill'' levels (to bridge large gaps between other identified efficiency levels) and/or to extrapolate to the max-tech level (particularly in cases where the max-tech level exceeds the maximum efficiency level currently available on the market).

In this proposed rulemaking, DOE relies on an efficiency-level approach due to the availability of robust data characterizing both performance and selling price at a variety of efficiency levels.

a. Baseline Efficiency

For each equipment class, DOE generally selects a baseline model as a reference point for each class, and measures changes resulting from potential energy conservation standards against the baseline. The baseline model in each equipment class represents the characteristics of an equipment typical of that class (*e.g.,* capacity, physical size). Generally, a baseline model is one that just meets current energy conservation standards, or, if no standards are in place, the baseline is typically the most common or least efficient unit on the market.

For all representative units, DOE modeled a baseline circulator pump as one with a PSC motor.

b. Higher Efficiency Levels

As part of DOE's analysis, the maximum available efficiency level is the highest efficiency unit currently available on the market. DOE also defines a ''max-tech'' efficiency level to represent the maximum possible efficiency for a given product.

For all representative units, DOE modeled a max-tech circulator pump as one with an ECM and operated on a differential temperature-based control scheme.

c. EL Analysis

DOE examined the influence of different paraments on wire-to-water efficiency including hydraulic power. Hydraulic power has a significant impact on wire to water efficiency as seen in the different representative units. To find the correlation, the relationship of power and wire to water efficiency were evaluated for both single speed induction and single speed ECM motors. Multiple relationships were tested with a logarithmic relationship being the most accurate. This logarithmic relationship can be used to set efficiency levels inclusive of all representative units across the ranges of horsepower.

To calculate wire to water efficiency at part-load conditions, wire-to-water efficiency at full-load conditions is multiplied by a part-load coefficient, represented by alpha (α). As instructed by the CPWG, a mean fit was developed for each part load test point across representative units to find a single value to use for alpha for each test point. This methodology was conducted independently for single speed induction, single speed ECM, and variable speed ECM to find unique alphas at each point for each motor type. The unique alpha values are provided in Table IV.2.

TABLE IV.2—MEAN ALPHA VALUES BY TEST POINT AND MOTOR CONFIGURATION

Motor configuration	Test point load	Mean alpha
Single Speed Induction	25	0.4671
	50	0.7674
	75	0.9425
	110	0.9835
Single Speed ECM	25	0.4845
	50	0.7730
	75	0.9408
	110	0.9841
Variable Speed ECM	25	0.5914
	50	0.8504
	75	0.9613

DOE sets EL 0 as the baseline configuration of circulator pumps representing the minimum efficiency available on the market. DOE used the logarithmic function developed when finding the relationship between hydraulic power and wire-to-water efficiency to find the lower second percentile of single speed induction circulator pumps to set as EL 0. DOE finds single speed circulator pumps with induction motors have the lowest wire-to-water efficiency and are being set as EL 0, as agreed on at CPWG meeting 8. (Docket No. EERE–2016–BT–STD–0004–0061, p. 15)

DOE set EL 1 to correspond approximately to single-speed induction motors with improved wire-to-water efficiency. EL 1 is an intermediate efficiency level between the baseline EL 0 and more efficient ECMs defined in higher efficiency levels. EL 1 was defined as the halfway between the most efficient single speed induction motors and the baseline used as EL 0.

EL 2 is set to correspond approximately to single-speed ECMs. The values for these circulator pumps are found using the same base logarithmic function that were used when finding the relationship between hydraulic power and wire-to-water efficiency. EL 2 corresponds to a CEI of 1.00, which is the level recommended by the CPWG in the November 2016 CPWG Recommendations.

EL 3 is set to correspond approximately to variable-speed ECMs with automatic proportional pressure control. The effect of a 50 percent proportional pressure control is applied using equation (9) for each part load test point. The wire-to-water efficiency at each test point is found using the alpha values for variable speed ECM values for alpha.

$$H = \left(\frac{1}{2}\right) H_{100\%} \left(\frac{Q_i}{Q_{100}} + 1\right) \tag{9}$$

Where:

H_i = total system head at each load point *i* (ft);

Q_i = flow rate at each load point *i* (gpm);

$Q_{100\%}$ = flow rate at 100 percent of BEP flow at maximum speed (gpm); and

$H_{100\%}$ = total pump head at 100 percent of BEP flow at maximum speed (ft).

EL 4 is the max-tech efficiency level, which represents the circulator pumps with the maximum possible efficiency. EL 4 is set as variable speed ECMs with automatic differential temperature control. The effects of the controls are calculated using equation (10). Similar to EL3, the wire-to-water efficiencies are found using the alpha values for variable speed ECMs.

$$H = \left(0.8 \left(\frac{Q_i}{Q_{100}}\right)^2 + 0.2\right) H_{100\%} \tag{10}$$

In response to the May 2021 RFI, Grundfos stated they do not believe there are any new technologies for DOE to consider and the maximum efficiency levels are appropriate for consideration. (Grundfos, No. 113 at p. 7).

For pumps that do not fit exactly into a representative unit, the DOE developed a continuous function for wire-to-water efficiency at BEP. The technique extends the representative units for each EL to compute wire-to-water efficiency at BEP for all circulator pumps by using the logarithmic function based on hydraulic power represented in equation (11). Variable *d* can be solved by using equation (12) and the variables for a and b are presented in Table IV.3 which contains different values for each efficiency level.

$$\eta_{WTW} = a \ln\left(P_{hydro} + b\right) + d \tag{11}$$

$$d = -a \ln(b) \tag{12}$$

Where:

η_{WTW} = wire-to-water efficiency

P_{hydro} = hydraulic power (HP);

TABLE IV.3—PARAMETERS USED TO SOLVE FOR WIRE-TO-WATER EFFICIENCY

EL	a	b
0	7.065278	0.003958
1	8.727971	0.003223
2	10.002583	0.001140
3	10.002583	0.001140
4	10.002583	0.001140

3. Cost Analysis

The cost analysis portion of the engineering analysis is conducted using one or a combination of cost approaches. The selection of cost approach depends on a suite of factors, including the availability and reliability of public information, characteristics of the regulated product, the availability and timeliness of purchasing the circulator pumps on the market. The cost approaches are summarized as follows:

• *Physical teardowns:* Under this approach, DOE physically dismantles a commercially available product, component-by-component, to develop a detailed bill of materials for the product.

• *Catalog teardowns:* In lieu of physically deconstructing a product, DOE identifies each component using parts diagrams (available from manufacturer websites or appliance repair websites, for example) to develop the bill of materials for the product.

• *Price surveys:* If neither a physical nor catalog teardown is feasible (for example, for tightly integrated products such as fluorescent lamps, which are infeasible to disassemble and for which parts diagrams are unavailable) or cost-prohibitive and otherwise impractical (*e.g.,* large commercial boilers), DOE conducts price surveys using publicly available pricing data published on major online retailer websites and/or by soliciting prices from distributors and other commercial channels.

In the present case, DOE conducted the analysis using a combination of physical teardowns and price surveys. The resulting bill of materials provides the basis for the manufacturer production cost (''MPC'') estimates.

4. Cost-Efficiency Results

The results of the engineering analysis are reported as cost-efficiency data (or ''curves'') in the form of wire-to-water efficiency versus MPC (in dollars). DOE developed 15 curves representing the 15 representative units in the analysis. The methodology for developing the curves started with determining the energy consumption for baseline equipment and MPCs for this equipment. Above the baseline, DOE implemented design options using the ratio of cost to savings, and implemented only one design option at each level. Design options were implemented until all available technologies were employed (*i.e.,* at a max-tech level).

Table IV.4, Table IV.5, Table IV.6 contain cost-efficiency results of the engineering analysis. MPCs are presented for circulator pumps with both ferrous and nonferrous housing material. Housing material does not significantly affect the energy consumption of circulator pumps, but does alter production cost. Housing material is discussed further in section IV.A.1.b. See TSD Chapter 5 for additional detail on the engineering analysis and TSD Appendix 5B for complete cost-efficiency results.

TABLE IV.4—ENGINEERING RESULTS—CP1, REP. UNITS 1–4

Rep unit	HP	Description	Construction	EL	MPC—Ferrous	MPC—Nonferrous
1	1/40	Single Speed, Induction	CP1	0	$31.34	$35.61
1	1/40	Improved Single Speed, Induction	CP1	1	31.34	35.61
1	1/40	Single Speed, ECM	CP1	2	47.91	51.87
1	1/40	Variable Speed, ECM, dP	CP1	3	59.23	63.18
1	1/40	Variable Speed, ECM, dT	CP1	4	68.28	72.24
1	1/40	Variable Speed, ECM, dT	CP1	5	68.28	72.24
2	1/40	Single Speed, Induction	CP1	0	34.44	39.13
2	1/40	Improved Single Speed, Induction	CP1	1	34.44	39.13
2	1/40	Single Speed, ECM	CP1	2	53.57	57.92
2	1/40	Variable Speed, ECM, dP	CP1	3	64.88	69.23
2	1/40	Variable Speed, ECM, dT	CP1	4	73.94	78.28
2	1/40	Variable Speed, ECM, dT	CP1	5	73.94	78.28
3	1/25	Single Speed, Induction	CP1	0	40.82	54.57
3	1/25	Improved Single Speed, Induction	CP1	1	40.82	54.57
3	1/25	Single Speed, ECM	CP1	2	65.65	78.41
3	1/25	Variable Speed, ECM, dP	CP1	3	76.96	89.72
3	1/25	Variable Speed, ECM, dT	CP1	4	86.02	98.78
3	1/25	Variable Speed, ECM, dT	CP1	5	86.02	98.78
4	1/25	Single Speed, Induction	CP1	0	40.82	54.57
4	1/25	Improved Single Speed, Induction	CP1	1	40.82	54.57
4	1/25	Single Speed, ECM	CP1	2	65.65	78.41
4	1/25	Variable Speed, ECM, dP	CP1	3	76.96	89.72
4	1/25	Variable Speed, ECM, dT	CP1	4	86.02	98.78
4	1/25	Variable Speed, ECM, dT	CP1	5	86.02	98.78

TABLE IV.5—ENGINEERING RESULTS—CP1, REP. UNITS 5–8

Rep unit	HP	Description	Construction	EL	MPC—Ferrous ($)	MPC—Nonferrous ($)
5	1/12	Single Speed, Induction	CP1	0	46.89	62.69
5	1/12	Improved Single Speed, Induction	CP1	1	46.89	62.69
5	1/12	Single Speed, ECM	CP1	2	84.51	99.17
5	1/12	Variable Speed, ECM, dP	CP1	3	95.83	110.48
5	1/12	Variable Speed, ECM, dT	CP1	4	104.88	119.54
5	1/12	Variable Speed, ECM, dT	CP1	5	104.88	119.54

TABLE IV.5—ENGINEERING RESULTS—CP1, REP. UNITS 5–8—Continued

Rep unit	HP	Description	Construction	EL	MPC—Ferrous ($)	MPC—Nonferrous ($)
6	1/6	Single Speed, Induction	CP1	0	58.59	78.32
6	1/6	Improved Single Speed, Induction	CP1	1	58.59	78.32
6	1/6	Single Speed, ECM	CP1	2	135.61	153.92
6	1/6	Variable Speed, ECM, dP	CP1	3	146.93	165.24
6	1/6	Variable Speed, ECM, dT	CP1	4	155.98	174.29
6	1/6	Variable Speed, ECM, dT	CP1	5	155.98	174.29
7	1/6	Single Speed, Induction	CP1	0	58.59	78.32
7	1/6	Improved Single Speed, Induction	CP1	1	58.59	78.32
7	1/6	Single Speed, ECM	CP1	2	135.61	153.92
7	1/6	Variable Speed, ECM, dP	CP1	3	146.93	165.24
7	1/6	Variable Speed, ECM, dT	CP1	4	155.98	174.29
7	1/6	Variable Speed, ECM, dT	CP1	5	155.98	174.29
8	1	Single Speed, Induction	CP1	0	246.65	314.15
8	1	Improved Single Speed, Induction	CP1	1	246.65	314.15
8	1	Single Speed, ECM	CP1	2	353.43	416.06
8	1	Variable Speed, ECM, dP	CP1	3	364.75	427.38
8	1	Variable Speed, ECM, dT	CP1	4	373.80	436.43
8	1	Variable Speed, ECM, dT	CP1	5	373.80	436.43

TABLE IV.6—ENGINEERING RESULTS—CP2 AND CP3

Rep unit	HP	Description	Construction	EL	MPC—Ferrous ($)	MPC—Nonferrous ($)
5	1/12	Single Speed, Induction	CP2	0	70.68	95.00
5	1/12	Improved Single Speed, Induction	CP2	1	70.68	95.00
5	1/12	Single Speed, ECM	CP2	2	116.64	139.20
5	1/12	Variable Speed, ECM, dP	CP2	3	127.95	150.52
5	1/12	Variable Speed, ECM, dT	CP2	4	137.00	159.57
5	1/12	Variable Speed, ECM, dT	CP2	5	137.00	159.57
6	1/6	Single Speed, Induction	CP2	0	110.21	142.23
6	1/6	Improved Single Speed, Induction	CP2	1	110.21	142.23
6	1/6	Single Speed, ECM	CP2	2	166.86	196.57
6	1/6	Variable Speed, ECM, dP	CP2	3	178.17	207.88
6	1/6	Variable Speed, ECM, dT	CP2	4	187.22	216.94
6	1/6	Variable Speed, ECM, dT	CP2	5	187.22	216.94
7	1/6	Single Speed, Induction	CP2	0	110.21	142.23
7	1/6	Improved Single Speed, Induction	CP2	1	110.21	142.23
7	1/6	Single Speed, ECM	CP2	2	166.86	196.57
7	1/6	Variable Speed, ECM, dP	CP2	3	178.17	207.88
7	1/6	Variable Speed, ECM, dT	CP2	4	187.22	216.94
7	1/6	Variable Speed, ECM, dT	CP2	5	187.22	216.94
5	1/12	Single Speed, Induction	CP3	0	103.19	130.25
5	1/12	Improved Single Speed, Induction	CP3	1	103.19	130.25
5	1/12	Single Speed, ECM	CP3	2	157.00	182.10
5	1/12	Variable Speed, ECM, dP	CP3	3	168.31	193.41
5	1/12	Variable Speed, ECM, dT	CP3	4	177.36	202.47
5	1/12	Variable Speed, ECM, dT	CP3	5	177.36	202.47
6	1/6	Single Speed, Induction	CP3	0	160.89	246.28
6	1/6	Improved Single Speed, Induction	CP3	1	160.89	246.28
6	1/6	Single Speed, ECM	CP3	2	224.59	303.82
6	1/6	Variable Speed, ECM, dP	CP3	3	235.91	315.13
6	1/6	Variable Speed, ECM, dT	CP3	4	244.96	324.19
6	1/6	Variable Speed, ECM, dT	CP3	5	244.96	324.19
7	1/6	Single Speed, Induction	CP3	0	160.89	246.28
7	1/6	Improved Single Speed, Induction	CP3	1	160.89	246.28
7	1/6	Single Speed, ECM	CP3	2	224.59	303.82
7	1/6	Variable Speed, ECM, dP	CP3	3	235.91	315.13
7	1/6	Variable Speed, ECM, dT	CP3	4	244.96	324.19
7	1/6	Variable Speed, ECM, dT	CP3	5	244.96	324.19
8	1	Single Speed, Induction	CP3	0	472.16	697.64
8	1	Improved Single Speed, Induction	CP3	1	472.16	697.64
8	1	Single Speed, ECM	CP3	2	604.20	813.41
8	1	Variable Speed, ECM, dP	CP3	3	615.52	824.73
8	1	Variable Speed, ECM, dT	CP3	4	624.57	833.78
8	1	Variable Speed, ECM, dT	CP3	5	624.57	833.78

5. Manufacturer Markup and Manufacturer Selling Price

To account for manufacturers' non-production costs and profit margin, DOE applies a non-production cost multiplier (the manufacturer markup) to the full MPC. The resulting MSP is the price at which the manufacturer can recover production and non-production costs. To calculate the manufacturer markups, DOE used data from 10–K reports [35] submitted to the U.S. Securities and Exchange Commission (''SEC'') by the publicly-owned circulator pump manufacturers. DOE then averaged the financial figures spanning the years 2019 to 2021 to calculate the initial estimate of markups for circulator pumps for this rulemaking. During the 2022 manufacturer interviews, DOE discussed the manufacturer markup with manufacturers and used the feedback to modify the manufacturer markup calculated through review of SEC 10–K reports.

To calculate the MSP for circulator pump equipment, DOE multiplied the calculated MPC at each efficiency level by the manufacturer markup. See chapter 12 of the NOPR TSD for more details about the manufacturer markup calculation and the MSP calculations.

D. Markups Analysis

The markups analysis develops appropriate markups (*e.g.,* retailer markups, distributor markups, contractor markups) in the distribution chain and sales taxes to convert the MSP estimates derived in the engineering analysis to consumer prices, which are then used in the LCC and PBP analysis and in the manufacturer impact analysis. At each step in the distribution channel, companies mark up equipment prices to cover business costs and profit margin.

For circulator pumps, the main parties in the distribution chain are (1) sales representatives (reps); (2) distributors; (3) contractors; and (4) original equipment manufacturers (OEMs). For each actor in the distribution chain, DOE developed baseline and incremental markups. Baseline markups are applied to the price of equipment with baseline efficiency, while incremental markups are applied to the difference in price between baseline and higher-efficiency models (the incremental cost increase). The incremental markup is typically less than the baseline markup and is designed to maintain similar per-unit operating profit before and after new or amended standards.[36]

DOE identified distribution channels for circulator pumps and estimated their respective shares of shipments by sector (residential and commercial) based on feedback from manufacturers and the CPWG (Docket No. EERE–2016–BT–STD–0004, No. 49 at p. 51), as shown in Table IV.7.

TABLE IV.7—CIRCULATOR PUMPS DISTRIBUTION CHANNELS AND RESPECTIVE MARKET SHARES

Channel: from manufacturer	Residential shipments share (%)	Commercial shipments share (%)
Sales Rep → Contractor → End User	....	37
Sales Rep → Distributor → Contractor → End User	73	36
Distributor → End User	....	2
Sales Rep → Distributor → End User	2	....
OEM → Contractor → End User	12	12
OEM → Distributor → Contractor → End User	13	13
Total	100	100

The sales representative in the distribution chain serves the role of a wholesale distributor, as they do not take commission from the sale, but buy the equipment and take title to it. The OEM channels represent sales of circulator pumps, which are included in other equipment, such as hot water boilers.

To estimate average baseline and incremental markups, DOE relied on several sources, including: (1) U.S. Census Bureau 2017 Annual Wholesale Trade Survey (for sales representatives and circulator wholesalers), (2) U.S. Census Bureau 2017 Economic Census data [37] on the residential and commercial building construction industry (for contractors), and (3) the Heating, Air Conditioning & Refrigeration Distributors International (''HARDI'') 2013 Profit Report [38] (for equipment wholesalers). In addition to markups of distribution channel costs, DOE applied state and local sales tax to derive the final consumer purchase prices for circulator pumps.

In the May 2021 RFI, DOE requested feedback on whether there have been market changes since the CPWG that would affect the distribution channels and the percentage of circulator pump shipments in each channel and sector, as shown in Table IV.7 of this document. HI commented that there have not been any market changes to warrant a different estimate (HI, No. 112 at p. 9), while Grundfos recommended manufacturer interviews for collection of relevant data (Grundfos, No. 113 at p. 8). During the 2022 manufacturer interviews, the general feedback from manufacturers was that there have not been significant market changes to justify any changes to the distribution channels shown in Table IV.7 of this document.

DOE requests comment on whether the distribution channels described above and the percentage of equipment sold through the different channels are appropriate and sufficient to describe the distribution markets for circulator pumps. Specifically, DOE requests comment and data on online sales of circulator pumps and the appropriate channel to characterize them.

[35] U.S. Securities and Exchange Commission, Annual 10–K Reports (Various Years) available at *sec.gov* (Last accessed June 15th, 2022).

[36] Because the projected price of standards-compliant products is typically higher than the price of baseline products, using the same markup for the incremental cost and the baseline cost would result in higher per-unit operating profit. While such an outcome is possible in the short run, DOE maintains that in markets that are reasonably competitive it is unlikely that standards would lead to a sustainable increase in profitability in the long run.

[37] U.S. Census Bureau, *2017 Economic Census Data*. available at *www.census.gov/programs-surveys/economic-census.html* (last accessed April 15, 2021).

[38] Heating, Air Conditioning & Refrigeration Distributors International (''HARDI''), *2013 HARDI Profit Report,* available at *hardinet.org/* (last accessed April 15, 2021). Note that the 2013 HARDI Profit Report is the latest version of the report.

Chapter 6 of the NOPR TSD provides details on DOE's development of markups for circulator pumps.

E. Energy Use Analysis

The purpose of the energy use analysis is to determine the annual energy consumption of circulator pumps at different efficiencies in representative U.S. single-family homes, multi-family residences, and commercial buildings, and to assess the energy savings potential of increased circulator pump efficiency. The energy use analysis estimates the range of energy use of circulator pumps in the field (*i.e.,* as they are actually used by consumers). It also provides the basis for other analyses DOE performs, particularly assessments of the energy savings and the savings in consumer operating costs that could result from adoption of amended or new standards.

To calculate the annual energy use (''AEU'') for circulator pumps, DOE multiplied the annual operating hours by the line input power (derived in the engineering analysis) at each operating point. The following sections describe how DOE estimated circulator pump energy use in the field for different applications, geographical areas, and use cases.

1. Circulator Pump Applications

DOE identified two primary applications for circulator pumps: Hydronic heating, and hot water recirculation. Hydronic heating systems are typically characterized by the use of water to move heating from sources such as hot water boilers to different rooms through pipes and radiating surfaces. Hot water recirculation systems serve the purpose of moving hot water from sources such as water heaters, through pipes, to water fixture outlets. For each of these applications, DOE developed estimates of operating hours and load profiles to characterize circulator pump energy use in the field.

Circulator pumps used in hydronic heating applications typically have cast iron housings, while those used in hot water recirculation applications have housings made of stainless steel or bronze. DOE collected sales data for circulator pumps, including their housing materials, through manufacturer interviews, and was able to estimate the market share of each application by horsepower and efficiency level. To estimate market shares by sector and horsepower rating, DOE relied primarily on industry expert input.

In the May 2021 RFI, DOE requested feedback on whether the breakdowns of circulator pumps by sector and application have changed since the CPWG proceedings. HI commented that there have not been any market changes to warrant a different estimate. (HI, No. 112 at p. 9) During the 2022 manufacturer interviews, DOE collected recent data and updated the estimated market shares by application. According to these data, the market share of circulator pumps used in hydronic heating applications is estimated at 66.6 percent, while that for hot water recirculation applications is 33.4 percent.

For details on the market breakdowns by sector and horsepower rating, for each application, see chapter 7 of the NOPR TSD.

2. Consumer Samples

To estimate the energy use of circulator pumps in field operating conditions, DOE typically develops consumer samples that are representative of installation and operating characteristics of how such equipment is used in the field, as well as distributions of annual energy use by application and market segment.

To develop a sample of circulator pump consumers, DOE used the Energy Information Administration's (EIA) 2012 commercial buildings energy consumption survey (CBECS) [39] and the 2015 residential energy consumption survey (RECS) [40]. For the commercial sector, DOE selected commercial buildings from CBECS and apartment buildings with five or more units from RECS. For the residential sector, DOE selected single family attached or detached buildings from RECS.[41] The following sections describe how DOE developed the consumer samples by application.

For hydronic heating, because there are no data in RECS and CBECS specifically on the use of circulator pumps, DOE used data on hot water boilers to develop its consumer sample. DOE adjusted the selection weight associated with the representative RECS and CBECS buildings containing boilers to effectively exclude steam boilers, which are not used with circulator pumps. To estimate the distribution of circulator pumps by geographical region, DOE also used information on each building's heated area by boilers to correlate it to circulator horsepower rating.

For hot water recirculation, there is limited information in RECS and CBECS. In the residential sector, DOE selected consumers based on building square footage and assumed that buildings greater than 3,000 square feet have a hot water recirculation system. (Docket No. EERE–2016–BT–STD–0004, No. 67 at pp. 171,172) DOE also assumed that only small (<1/12 hp) circulator pumps are installed in residential buildings. For the commercial sector, DOE first selected buildings in CBECS with instant hot water. Further, DOE assigned a circulator pump size category based on the number of floors in each building. The commercial segment of the RECS sample was defined as multi-family buildings with more than four units. Similar to the hydronic heating application, to determine a distribution by region by representative unit, DOE assigned circulator pump sizes (*i.e.,* horsepower ratings) to building types based on the number of floors in each building.

The CA IOUs commented that, specific to California, a 2017 workpaper report [42] estimates that 93 percent of the California market is hot water circulator pumps (as opposed to hydronic) (CA IOUs, No. 116 at p. 6). DOE reviewed the report cited by the CA IOUs and notes that this estimate is based on market data from a subset of circulator pump manufacturers compared to the one analyzed by DOE, which may lead to different market share estimates by application. Regardless, DOE's estimate for circulator pumps used in hot water recirculation systems in California is approximately 80 percent, which is generally consistent with the estimate cited by the CA IOUs.

For details on the consumer sample methodology, see chapter 7 of the NOPR TSD.

3. Operating Hours

DOE developed annual operating hour estimates by sector (commercial, residential) and application (hydronic heating, hot water recirculation).

a. Hydronic Heating

For hydronic heating applications in the residential sector, operating hours per year were estimated based on two sources: 2015 confidential residential

[39] U.S. Department of Energy–Energy Information Administration. 2012 Commercial Buildings Energy Consumption Survey (CBECS). 2012. (Last accessed June 1, 2022.) *https://www.eia.gov/consumption/commercial/data/2012/.*

[40] U.S. Department of Energy: Energy Information Administration. 2015 Residential Energy Consumption Survey (RECS). 2015. (Last accessed June 22, 2022.) *https://www.eia.gov/consumption/residential/data/2015/.*

[41] For the final rule, DOE anticipates using the 2018 CBECS and the 2020 RECS to develop the consumer sample, for the commercial and residential sectors, respectively.

[42] Workpaper PGECOPUM107, High Performance Circulator Pumps, S. Putnam, 2017. Last accessed July 21, 2022. Available at *https://deeresources.net/workpapers.*

field metering data from Vermont, and a 2012–2013 residential metering study in Ithaca, NY.[43] DOE used the data from these metering data to establish a relationship between heating degree days (HDDs) and circulator pump operating hours. DOE correlated monthly operating hours with corresponding HDDs to annual operating hours. DOE then used the geographic distribution of consumers, as derived from the consumer sample, to estimate weighted-average HDDs for each region. For the residential sector, this scaling factor was 0.33 HPY/HDD. For the commercial sector, the CPWG recommended a scaling factor of 0.45 HPY/HDD. (Docket No. EERE–2016–BT–STD–0004, No. 100 at pp. 122–123). The weighted average operating hours per year for the hydronic heating application were estimated at approximately 1,970 and 2,200 for the residential and commercial sector, respectively.

b. Hot Water Recirculation

For circulator pumps used in hot water recirculation applications, DOE developed operating hour estimates based on their associated control types (Docket No. EERE–2016–BT–STD–0004, No. 60 at p. 74), as shown in Table IV.8.

TABLE IV.8—CIRCULATOR PUMP OPERATING HOURS FOR HOT WATER RECIRCULATION

Control type	Sector	Fraction of consumers (%)	Operating hours per year	Notes
No Control	Residential	50	8,760	Constant Operation.
	Commercial.			
Timer	Residential	25	7,300	50 operating constantly, and 50 operating 16 hrs/day.
	Commercial.		6,570	50 operating constantly and 50 operating 12hrs/day.
Aquastat	Residential	20	1,095	3 hrs per day.
	Commercial.			
On Demand	Residential	5	61	10 minutes per day.*
	Commercial.		122	20 minutes per day.*

* Assuming that circulator pumps operate for 30 sec for each demand "push"

In the May 2021 RFI, DOE requested information on any updated or recent data sources to inform and validate the circulator pump operating hours in the residential and commercial sectors and across all applications, as well as any technology or market changes since the term sheet to warrant a different approach on the circulator pump operating hours.

NEEA commented that DOE's analysis assumptions are still reasonable and provided information from a NEEA research study,[44] which surveyed circulator pumps in hydronic heating applications. NEEA mentioned that the study's operating hour estimate, which, for residential hydronic heating systems, was 3,291 hours per year in the Pacific Northwest region, was substantially similar to those estimated by DOE for the same region. (NEEA, No. 115 at pp. 5–6). HI also mentioned the NEEA study and suggested that DOE evaluate the circulator pump operating hours approach based on recent studies and their expansion of control types within hot water recirculation (HI, No. 112 at p. 9). Grundfos commented that the operating hour estimates are generally accurate and that it was not aware of relevant studies (Grundfos, No. 113 at p. 9). Regarding specifically circulator pumps with on-demand controls, HI commented that there has not been a market change to warrant a different estimate (HI, No. 112 at p. 9), while Grundfos stated that the fraction of on-demand controls is accurate (Grundfos, No. 113 at p. 9).

DOE appreciates the data provided by NEEA and continues to use the same approach as presented in during the CPWG meetings for the hydronic heating application, and discussed earlier in this section. In addition, during the 2022 manufacturer interviews, with regard to the hot water recirculation application, manufacturers commented that there have been zero or negligible changes in market distribution of hot water recirculation control types. Therefore, DOE maintained the market breakdowns and operating hours (presented in Table IV.8) for this application.

4. Load Profiles

To estimate the power consumption of each representative unit at each efficiency level, DOE used the following methodology: For each representative unit, DOE defined a range of typical system curves representing different piping and fluid configurations and bounded the representative unit's pump curve derived in the engineering analysis within those system curves. The upper and lower boundaries of this range of system curves correspond to a maximum (Q_{max}) and minimum (Q_{min}) value of volumetric flow. The value of (Q_{max}) is capped to 150% of BEP flow at most, while the value of the value of is capped to at least 25% of BEP flow.

For single speed circulator pumps (ELs 0–2) in single zone applications, DOE-randomly selects a single operating point (Q_0) within the boundaries of the system curves such that Q_0 is between Q_{min} and Q_{max}. The AEU is then calculated by multiplying the power consumption at the volumetric flow Q_0, as derived in the engineering analysis, by the annual operating hours.

For variable-speed circulator pumps (ELs 3–4) in single-zone applications, similarly, DOE randomly selects a single operating point (Q_0) within the boundaries of the system curves, such that Q_0 is between Q_{min} and Q_{max}After the operating point is selected, the procedure to determine the AEU varies depending on the value of Q_0: If the selected operating point (Q_0) has a flow that is equal or higher than Q_{BEP}, the method is the same as the one for single speed circulator pumps in single zones. For operating points where $Q_0 < Q_{BEP}$, DOE assumes that the circulator pump reduces its speed and operates at the intersection of the corresponding system curve and the control curve of each EL (dP or dT), at a flow Q_x. The AEU is then calculated by multiplying the power consumption at the volumetric flow Q_x, as derived in the engineering

[43] Arena, L. and O. Faakye. Optimizing Hydronic System Performance in Residential Applications. 2013. U.S. Department of Energy Building Technologies Office. Last accessed July 21, 2022. *https://www.nrel.gov/docs/fy14osti/60200.pdf.*

[44] Cadeo Group. Extended Motor Products Savings Validation Research on Clean Water Pumps and Circulators. 2019. Northwest Energy Efficiency Alliance. Report No. E19–307. (Last accessed June 23, 2022.) *https://neea.org/resources/extended-motor-products-savings-validation-research-on-clean-water-pumps-and-circulators.*

analysis, by the annual operating hours, after adjusting the hours to maintain the same heat as Q_0.

For circulator pumps in multi-zone applications DOE modeled their operation by assuming that representative multi-zone systems have three zones, resulting in two additional operating points (Q_- and Q_+), which are equidistant from a randomly selected operating point, Q_0, and are within the allowable operating flow (between (Q_{min} and Q_{max}) as defined by the representative unit's characteristic system curves. (Docket #0004, No. 61 at p. 88)

For variable speed circulator pumps (ELs 3–4), DOE estimated the energy use from the variable speed controls assuming all shipments would be matched with end-use appliances that reflect variable speed field operation. DOE understands that some end-use appliances may not be able to respond to variable speed circulator pump controls and therefore, the variable speed control operation would not be realized in the field. DOE seeks comment on the fraction of the market that would not see the benefits of variable speed circulator pump controls in the field due to the limitations of the system.

Chapter 7 of the NOPR TSD provides details on DOE's energy use analysis for circulator pumps.

F. Life-Cycle Cost and Payback Period Analysis

DOE conducted LCC and PBP analyses to evaluate the economic impacts on individual consumers of potential energy conservation standards for circulator pumps. The effect of new or amended energy conservation standards on individual consumers usually involves a reduction in operating cost and an increase in purchase cost. DOE used the following two metrics to measure consumer impacts:

• The LCC is the total consumer expense of an appliance or product over the life of that product, consisting of total installed cost (manufacturer selling price, distribution chain markups, sales tax, and installation costs) plus operating costs (expenses for energy use, maintenance, and repair). To compute the operating costs, DOE discounts future operating costs to the time of purchase and sums them over the lifetime of the product.

• The PBP is the estimated amount of time (in years) it takes consumers to recover the increased purchase cost (including installation) of a more-efficient product through lower operating costs. DOE calculates the PBP by dividing the change in purchase cost at higher efficiency levels by the change in annual operating cost for the year that amended or new standards are assumed to take effect.

For any given efficiency level, DOE measures the change in LCC relative to the LCC in the no-new-standards case, which reflects the estimated efficiency distribution of circulator pumps in the absence of new energy conservation standards. In contrast, the PBP for a given efficiency level is measured relative to the baseline product.

For each considered efficiency level in each product class, DOE calculated the LCC and PBP for a nationally representative set of commercial and residential consumers. As stated previously, DOE developed household samples from the 2015 RECS and the 2012 CBECS, for the residential and commercial sectors, respectively. For each sample consumer, DOE determined the energy consumption for circulator pumps and the appropriate energy price. By developing a representative sample of consumers, the analysis captured the variability in energy consumption and energy prices associated with the use of circulator pumps.

Inputs to the calculation of total installed cost include the cost of the product—which includes MPCs, manufacturer markups, retailer and distributor markups, and sales taxes—and installation costs. Inputs to the calculation of operating expenses include annual energy consumption, energy prices and price projections, repair and maintenance costs, product lifetimes, and discount rates. DOE created distributions of values for product lifetime, discount rates, and sales taxes, with probabilities attached to each value, to account for their uncertainty and variability.

The computer model DOE uses to calculate the LCC and PBP relies on a Monte Carlo simulation to incorporate uncertainty and variability into the analysis. The Monte Carlo simulations randomly sample input values from the probability distributions and consumer user samples. The model calculated the LCC and PBP for a sample of 10,000 consumers per simulation run. The analytical results include a distribution of 10,000 data points showing the range of LCC savings. In performing an iteration of the Monte Carlo simulation for a given consumer, product efficiency is chosen based on its probability. By accounting for consumers who purchase more-efficient products in the no-new-standards case, DOE avoids overstating the potential benefits from increasing product efficiency.

DOE calculated the LCC and PBP for all consumers of circulator pumps as if each were to purchase a new product in the expected year of required compliance with new or amended standards. As discussed in section III.G, new and amended standards would apply to circulator pumps manufactured 2 years after the date on which any new or amended standard is published. At this time, DOE estimates publication of a final rule in 2024. Therefore, for purposes of its analysis, DOE used 2026 as the first year of compliance with standards for circulator pumps.

Table IV.9 summarizes the approach and data DOE used to derive inputs to the LCC and PBP calculations. The subsections that follow provide further discussion. Details of the LCC model, and of all the inputs to the LCC and PBP analyses, are contained in chapter 8 of the NOPR TSD and its appendices.

TABLE IV.9—SUMMARY OF INPUTS AND METHODS FOR THE LCC AND PBP ANALYSIS *

Inputs	Source/method
Product Cost	Derived by multiplying MPCs by manufacturer and retailer markups and sales tax, as appropriate.
Installation Costs	Installation cost determined with data from RSMeans and CPWG input.
Annual Energy Use	Derived in energy use analysis. Varies by geographic location, control type, sector, and application.
Energy Prices	Based on 2021 average and marginal electricity price data from the Edison Electric Institute. Electricity prices vary by season and U.S. region.
Energy Price Trends	Based on *AEO2022* price projections.
Repair and Maintenance Costs	Varies by circulator pump variety.
Product Lifetime	CP1: 10 years average; CP2: 15 years average; CP3 20 years average.
Discount Rates	Approach involves identifying all possible debt or asset classes that might be used to purchase the considered appliances, or might be affected indirectly. Primary data source was the Federal Reserve Board's Survey of Consumer Finances.

TABLE IV.9—SUMMARY OF INPUTS AND METHODS FOR THE LCC AND PBP ANALYSIS *—Continued

Inputs	Source/method
Efficiency Distribution	Estimated based on manufacturer-provided data. An efficiency trend is applied for the no-standards case.
Compliance Date	2026.

* References for the data sources mentioned in this table are provided in the sections following the table or in chapter 8 of the NOPR TSD.

1. Product Cost

To calculate consumer product costs, DOE multiplied the MPCs developed in the engineering analysis by the markups described previously (along with sales taxes). DOE used different markups for baseline products and higher-efficiency products, because DOE applies an incremental markup to the increase in MSP associated with higher-efficiency products.

2. Installation Cost

Installation cost includes labor, overhead, and any miscellaneous materials and parts associated with installing a circulator pump in the place of use. DOE derived installation costs for circulator pumps based on input from the CPWG and data from RSMeans.[45] (Docket #0004, No. 67 at p. 266)

DOE assumed that circulator pumps without variable speed controls (ELs 0–2) require a labor time of 3 hours and an additional 30 minutes for circulator pumps with electronic controls (ELs 3 and 4). (Docket #0004, No. 67 at p. 266) RSMeans provides estimates on the labor hours and labor costs required to install equipment. In the NOPR, DOE derived the installation cost for circulator pumps as the product of labor hours and time required to install a circulator pump. Installation costs vary by geographic location and efficiency level. During the 2022 manufacturer interviews, manufacturers agreed with DOE's approach to estimate installation costs. Annual Energy Consumption

For each sampled consumer, DOE determined the energy consumption for a circulator pump at different efficiency levels using the approach described previously in section IV.E. of this document.

3. Annual Energy Consumption

For each sampled consumer, DOE determined the AEU for a circulator pump at different efficiency levels using the approach described previously in section IV.E. of this document.

4. Energy Prices

Because marginal electricity price more accurately captures the incremental savings associated with a change in energy use from higher efficiency, it provides a better representation of incremental change in consumer costs than average electricity prices. Therefore, DOE applied average electricity prices for the energy use of the product purchased in the no-new-standards case, and marginal electricity prices for the incremental change in energy use associated with the other efficiency levels considered.

DOE derived electricity prices in 2021 using data from EEI Typical Bills and Average Rates reports. Based upon comprehensive, industry-wide surveys, this semi-annual report presents typical monthly electric bills and average kilowatt-hour costs to the customer as charged by investor-owned utilities. For the residential sector, DOE calculated electricity prices using the methodology described in Coughlin and Beraki (2018).[46] For the commercial sector, DOE calculated electricity prices using the methodology described in Coughlin and Beraki (2019).[47]

DOE's methodology allows electricity prices to vary by sector, region and season. In the analysis, variability in electricity prices is chosen to be consistent with the way the consumer economic and energy use characteristics are defined in the LCC analysis.

To estimate electricity prices in future years, DOE multiplied the 2021 regional energy prices by a projection of annual change in national-average residential or commercial energy price from *AEO2022,* which has an end year of 2050.[48] For each consumer sampled, DOE applied the projection for the geographic location in which the consumer was located. To estimate price trends after 2050, DOE assumed that the regional prices would remain at the 2050 value.

DOE used the electricity price trends associated with the AEO Reference case, which is a business-as-usual estimate, given known market, demographic, and technological trends. DOE also included AEO High Economic Growth and AEO Low Economic Growth scenarios in the analysis. The high- and low-growth cases show the projected effects of alternative economic growth assumptions on energy prices.

For a detailed discussion of the development of electricity prices, see chapter 8 of the NOPR TSD.

5. Maintenance and Repair Costs

Repair costs are associated with repairing or replacing product components that have failed in equipment; maintenance costs are associated with maintaining the operation of the equipment. Typically, small incremental increases in equipment efficiency produce no, or only minor, changes in repair and maintenance costs compared to baseline efficiency products.

DOE assumed that only certain types of CP3 circulators require annual maintenance through oil lubrication. Based on CPWG feedback, DOE assumed that 50 percent of commercial consumers have a maintenance cost of $10 per year and 25 percent of residential consumers have a maintenance cost of $20 per year, which result in an overall $5 annual maintenance cost for CP3 circulators in each of the two applications. (Docket #0004, No. 47 at pp. 324–327)

Repair costs consist of both labor and replacement part costs. DOE assumed that repair costs for CP1 circulators are negligible because consumers tend to discard such products when they fail. For CP2 and CP3 circulator pumps, DOE assumed that repairs occur every 7 years. According to CPWG feedback and manufacturer interview input, typical repairs for CP2 and CP3 include seal replacements and coupler plus motor mount replacements, respectively. DOE assumed consistent labor time with installation costs, which is 3 hours for seal replacement and 1.5 hours for coupler and motor mount replacement. Additionally, DOE assumes there is no variation in repair costs between a

[45] RSMeans. *2021 RSMeans Plumbing Cost Data.* Rockland, MA. *https://www.rsmeans.com.*

[46] Coughlin, K. and B. Beraki.2018. Residential Electricity Prices: A Review of Data Sources and Estimation Methods. Lawrence Berkeley National Lab. Berkeley, CA. Report No. LBNL–2001169. *https://ees.lbl.gov/publications/residential-electricity-prices-review.*

[47] Coughlin, K. and B. Beraki. 2019. Non-residential Electricity Prices: A Review of Data Sources and Estimation Methods. Lawrence Berkeley National Lab. Berkeley, CA. Report No. LBNL–2001203. *https://ees.lbl.gov/publications/non-residential-electricity-prices.*

[48] U.S. Energy Information Administration. *Annual Energy Outlook 2022.* 2022. Washington, DC (Last accessed April 13, 2022.) *https://www.eia.gov/outlooks/aeo/index.php.*

baseline efficiency circulator and a higher efficiency circulator. During the 2022 manufacturer interviews, manufacturers agreed with DOE's approach to estimate maintenance and repair costs.

6. Product Lifetime

Equipment lifetime is the age when a unit of circulator equipment is retired from service. DOE estimated lifetimes and developed lifetime distributions for circulator pumps primarily based on manufacturer interviews conducted in 2016 and CPWG feedback (Docket #0004, No. 37 at p. 74). The data collected by manufacturers allowed DOE to develop a survival function, which provides a distribution of lifetimes ranging from a minimum of 3 years based on warranty covered period, to a maximum of 50 years for CP1, CP2, or CP3 respectively. DOE assumed circulator lifetimes do not vary across efficiency levels. Table IV.10 shows the average lifetimes by circulator variety.

TABLE IV.10—AVERAGE CIRCULATOR PUMP LIFETIME BY CIRCULATOR PUMP VARIETY

Circulator pump variety	Average lifetime (years)
CP1	10
CP2	15
CP3	20

During the 2022 manufacturer interviews, DOE solicited additional feedback from manufacturers on the lifetime assumptions presented in Table IV.10, and the general consensus was that there have not been significant technological changes to warrant a different estimate on the circulator pump lifetimes.

7. Discount Rates

In the calculation of the LCC, DOE applies discount rates appropriate to residential and commercial consumers to estimate the present value of future operating cost savings. The subsections below provide information on the derivation of the discount rates by sector. See chapter 7 of the SNOPR TSD for further details on the development of discount rates.

a. Residential

DOE applies weighted average discount rates calculated from consumer debt and asset data, rather than marginal or implicit discount rates.[49] The LCC analysis estimates net present value over the lifetime of the equipment, so the appropriate discount rate will reflect the general opportunity cost of household funds, taking this time scale into account. Given the long-time horizon modeled in the LCC analysis, the application of a marginal interest rate associated with an initial source of funds is inaccurate. Regardless of the method of purchase, consumers are expected to continue to rebalance their debt and asset holdings over the LCC analysis period, based on the restrictions consumers face in their debt payment requirements and the relative size of the interest rates available on debts and assets. DOE estimates the aggregate impact of this rebalancing using the historical distribution of debts and assets.

To establish residential discount rates for the LCC analysis, DOE identified all relevant household debt or asset classes in order to approximate a consumer's opportunity cost of funds related to appliance energy cost savings. It estimated the average percentage shares of the various types of debt and equity by household income group using data from the Federal Reserve Board's Survey of Consumer Finances[50] (''SCF'') for 1995, 1998, 2001, 2004, 2007, 2010, 2013, and 2019. Using the SCF and other sources, DOE developed a distribution of rates for each type of debt and asset by income group to represent the rates that may apply in the year in which standards would take effect. DOE assigned each sample household a specific discount rate drawn from one of the distributions. The average rate across all types of household debt and equity and income groups, weighted by the shares of each type, is 4.0 percent.

b. Commercial

For commercial consumers, DOE used the cost of capital to estimate the present value of cash flows to be derived from a typical company project or investment. Most companies use both debt and equity capital to fund investments, so the cost of capital is the weighted-average cost to the firm of equity and debt financing. This corporate finance approach is referred to as the weighted-average cost of capital. DOE used currently available economic data in developing commercial discount rates, with Damodaran Online being the primary data source.[51] The average discount rate across the commercial building types is 6.9 percent.

8. Energy Efficiency Distribution in the No-New-Standards Case

To accurately estimate the share of consumers that would be affected by a potential energy conservation standard at a particular efficiency level, DOE's LCC analysis considered the projected distribution (market shares) of equipment efficiencies under the no-new-standards case (*i.e.,* the case without amended or new energy conservation standards).

To estimate the energy efficiency distribution of circulator pumps for the assumed compliance year (2026), DOE first analyzed detailed confidential manufacturer shipments data from 2015, broken down by efficiency level, circulator variety, and nominal horsepower. During the 2016 manufacturer interviews, DOE also collected aggregated historical circulator pump efficiency data. Based on these data, DOE developed an efficiency trend between the year for which DOE had detailed data (2015) and the expected first year of compliance. According to CPWG feedback, DOE applied an efficiency trend from baseline (EL 0) circulator pumps to circulator pumps with ECMs (ELs 2–4). (Docket #0004, No. 78 at p. 6)

In the May 2021 RFI, DOE requested information on whether any changes in the circulator pump market since 2015 have affected the market efficiency distribution of circulator pumps. NEEA discussed their energy efficiency program for circulator pumps since mid 2020 and the circulator sales data collected from circulator manufacturer representatives covering the entire Northwest at the start of 2020. NEEA stated that more than two-thirds of circulator pumps sold by participants in the Northwest are not equipped with ECM. NEEA stated that fewer than one-fifth of circulator pumps are equipped with speed control technology. (NEEA, No. 115 at pp. 2–3, 6) HI stated that small incremental growth is occurring

[49] The implicit discount rate is inferred from a consumer purchase decision between two otherwise identical goods with different first cost and operating cost. It is the interest rate that equates the increment of first cost to the difference in net present value of lifetime operating cost, incorporating the influence of several factors: transaction costs; risk premiums and response to uncertainty; time preferences; interest rates at which a consumer is able to borrow or lend. The implicit discount rate is not appropriate for the LCC analysis because it reflects a range of factors that influence consumer purchase decisions, rather than the opportunity cost of the funds that are used in purchases.

[50] U.S. Board of Governors of the Federal Reserve System. *Survey of Consumer Finances.* 1995, 1998, 2001, 2004, 2007, 2010, 2013, 2016, and 2019. (Last accessed June 22, 2022.) *https://www.federalreserve.gov/econresdata/scf/scfindex.htm.*

[51] Damodaran, A. *Data Page: Historical Returns on Stocks, Bonds and Bills-United States.* 2021. (Last accessed April 26, 2022.) *https://pages.stern.nyu.edu/~adamodar/.*

for ECMs, but first cost is a barrier. (HI, No. 112 at p. 9–10) Grundfos suggested market changes have affected distribution of circulator pumps since 2015 and DOE should use manufacturer and market interviews to update their dataset. (Grundfos, No. 113 at p. 9)

During the 2022 manufacturer interviews, DOE collected additional aggregated historical circulator pump efficiency data (ranging from 2016 to 2021). Based on these data, DOE retained the methodology described earlier, but updated the efficiency trend, which was used to project the no-standards-case efficiency distribution at the assumed compliance year (2026) and beyond. See chapter 8 of the NOPR TSD for further information on the derivation of the efficiency distributions.

DOE seeks comment on the approach and inputs used to develop no-new standards case efficiency distribution.

9. Payback Period Analysis

The payback period is the amount of time it takes the consumer to recover the additional installed cost of more-efficient equipment, compared to baseline equipment, through energy cost savings. Payback periods are expressed in years. Payback periods that exceed the life of the equipment mean that the increased total installed cost is not recovered in reduced operating expenses.

The inputs to the PBP calculation for each efficiency level are the change in total installed cost of the equipment and the change in the first-year annual operating expenditures relative to the baseline. The PBP calculation uses the same inputs as the LCC analysis, except that discount rates are not needed.

As noted previously, EPCA establishes a rebuttable presumption that a standard is economically justified if the Secretary finds that the additional cost to the consumer of purchasing a product complying with an energy conservation standard level will be less than three times the value of the first year's energy savings resulting from the standard, as calculated under the applicable test procedure. (42 U.S.C. 6295(o)(2)(B)(iii)) For each considered efficiency level, DOE determined the value of the first year's energy savings by calculating the energy savings in accordance with the applicable DOE test procedure, and multiplying those savings by the average energy price projection for the year in which compliance with the standards would be required.

G. Shipments Analysis

DOE uses projections of annual product shipments to calculate the national impacts of potential amended or new energy conservation standards on energy use, NPV, and future manufacturer cash flows.[52] The shipments model takes an accounting approach, tracking market shares of each product class and the vintage of units in the stock. Stock accounting uses product shipments as inputs to estimate the age distribution of in-service product stocks for all years. The age distribution of in-service product stocks is a key input to calculations of both the NES and NPV, because operating costs for any year depend on the age distribution of the stock.

In the accounting approach, shipments are the result either of demand for the replacement of existing equipment, or of demand for equipment from new commercial and residential construction. Replacements in any projection year are based on (a) shipments in prior years, and (b) the lifetime of previously shipped equipment. Demand for new equipment is based on the rate of increase in commercial floor space (in the commercial sector), and residential housing (in the residential sector). In each year of shipments projections, retiring equipment is removed from a record of existing stock, and new shipments are added. DOE accounts for demand lost to demolitions (*i.e.,* loss of circulator pumps that will not be replaced) by assuming that a small fraction of stock is retired without being replaced in each year, based on a derived demolition rate for each sector.

DOE collected confidential historical shipments data for the period 2013—2021 from manufacturer interviews held in 2016 (during the CPWG) and 2022. Shipments data provided by manufacturers were broken down by circulator variety, nominal horsepower rating, and efficiency. Table IV.11 presents historical circulator pumps shipments. Note that due to confidentiality concerns, DOE is only able to present aggregated circulator pump shipments.

TABLE IV.11—HISTORICAL CIRCULATOR PUMP SHIPMENTS

Year	Shipments (million units)
2013	1.676
2014	1.812
2015	1.848
2016	1.735
2017	1.788
2018	2.067
2019	1.883
2020	1.829
2021	2.193

[52] DOE uses data on manufacturer shipments as a proxy for national sales, as aggregate data on sales are lacking. In general, one would expect a close correspondence between shipments and sales.

1. No-New-Standards Case Shipments Projections

The no-new-standards case shipments projections are an estimate of how much of each equipment type would be shipped in the absence of any new or amended standard. DOE projected shipments in the no-new-standards case by circulator pump variety (CP1, CP2, and CP3) as well as sector & application.

In response to DOE's request for shipments data in the May 2021 RFI, both Grundfos and HI recommended DOE conduct market interviews to collect relevant sales data (Grundfos, No. 113 at p. 9) (HI, No. 112 at p. 10). HI also added that in 2021, HI updated its statistics reporting to include circulator pumps as a category, but reporting is limited due confidentiality rules. (HI, No. 112 at p. 10)

DOE also requested information on any market changes since 2015 that would justify using market drivers and saturation trends that are different than those recommended by the CPWG. HI Commented that some areas of the market have started to move toward more controlled products (boiler OEMs, and where utility incentives are available). However, HI did not believe this has impacted the CPWGs recommendations (HI, No. 112 at p. 10). Grundfos estimated that the heating market growth is near 0.0% and the hot water recirculation market is well above 1%; and combined the market growth is near 1% (Grundfos, No. 113 at p. 9).

In the no-new-standards case, DOE assumes that demand for new installations would be met by CP1 circulator pumps alone. This is based on manufacturer feedback and historical shipments trends (see chapter 9 of the NOPR TSD for details). New demand is based on AEO 2022[3] projections of commercial floorspace & new construction (for demand to the commercial sector), and projections of residential housing stock & starts (for demand to the residential sector). DOE further assumes that over time, a decreasing amount of demand for equipment in the hydronic heating application is met by circulator pumps. For each year in the analysis period (2026–2055), DOE assumes a 2 percent reduction of new demand for circulator pumps in the hydronic heating application compared to the previous year, according to Census data on new heating systems.[53]

DOE assumed that demand for replacements would be met by circulator pumps of the same variety (*e.g.,* CP2 only replaced by CP2) in each sector and application. After calculating retirements of existing pumps based on those previously shipped and equipment lifetimes, DOE assumes that some of this quantity will not be replaced due to demolition. DOE estimates the demolition rate of existing equipment stock by using the AEO 2022 projections of new commercial floorspace and floorspace growth in the commercial sector, and new housing starts and housing stock in the residential sector.

DOE seeks comment on the approach and inputs used to develop no-new standards case shipments projections.

2. Standards-Case Shipment Projections

The standards-case shipments projections account for the effects of potential standards on shipments. DOE assumed a ''roll-up'' scenario to estimate standards-case shipments, wherein the no-new-standards-case shipments that would be below a candidate equipment standard beginning in an assumed compliance year (2026) are ''rolled up'' to the minimum qualifying equipment efficiency level at that candidate standard.

DOE seeks comment on the approach and inputs used to develop the different standards case shipments projections.

See chapter 9 of the NOPR TSD for details on the shipments analysis.

H. National Impact Analysis

The NIA assesses the NES and the NPV from a national perspective of total consumer costs and savings that would be expected to result from new or amended standards at specific efficiency levels.[54] (''Consumer'' in this context refers to consumers of the product being regulated.) DOE calculates the NES and NPV for the potential standard levels considered based on projections of annual equipment shipments, along with the annual energy consumption and total installed cost data from the energy use and LCC analyses. For the present analysis, DOE projected the energy savings, operating cost savings, product costs, and NPV of consumer benefits over the lifetime of circulator pumps sold from 2026 through 2055.

DOE evaluates the impacts of new or amended standards by comparing a case without such standards with standards-case projections. The no-new-standards case characterizes energy use and consumer costs for each product class in the absence of new or amended energy conservation standards. For this projection, DOE considers historical trends in efficiency and various forces that are likely to affect the mix of efficiencies over time. DOE compares the no-new-standards case with projections characterizing the market for each product class if DOE adopted new or amended standards at specific energy efficiency levels (*i.e.,* the TSLs or standards cases) for that class. For the standards cases, DOE considers how a given standard would likely affect the market shares of products with efficiencies greater than the standard.

In response to the May 2021 RFI, HI and Grundfos recommends DOE include current market data in their analyses. (HI, No. 112 at p. 7; Grundfos, No. 113 at p. 6) Updated market data was collected during the 2022 manufacturer interviews. However, the data suggest similar ranges of efficiencies are available in market, so 2016 performances remained with costs updated for inflation.

DOE uses a model coded in the Python programming language to calculate the energy savings and the national consumer costs and savings from each TSL and presents the results in the form of a spreadsheet. Interested parties can review DOE's analyses by changing various input quantities within the spreadsheet. The NIA uses typical values (as opposed to probability distributions) as inputs.

Table IV.12 summarizes the inputs and methods DOE used for the NIA analysis for the NOPR. Discussion of these inputs and methods follows the table. See chapter 10 of the NOPR TSD for further details.

TABLE IV.12—SUMMARY OF INPUTS AND METHODS FOR THE NATIONAL IMPACT ANALYSIS

Inputs	Method
Shipments	Annual shipments from shipments model.
Compliance Date of Standard	2026.
Efficiency Trends	Applied efficiency trend based on historical efficiency data
Annual Energy Consumption per Unit	Annual weighted-average values are a function of energy use at each TSL.
Total Installed Cost per Unit	Annual weighted-average values are a function of cost at each TSL.Incorporates projection of future product prices based on historical data.
Annual Energy Cost per Unit	Annual weighted-average values as a function of the annual energy consumption per unit and energy prices.
Repair and Maintenance Cost per Unit	Annual values do not change with efficiency level.
Energy Price Trends	*AEO2022* projections (to 2050) and constant after 2050.
Energy Site-to-Primary and FFC Conversion	A time-series conversion factor based on *AEO2022.*
Discount Rate	3 percent and 7 percent.
Present Year	2021.

1. Equipment Efficiency Trends

A key component of the NIA is the trend in energy efficiency projected for the no-new-standards case and each of the standards cases. Section IV.F.8 of this document describes how DOE developed an energy efficiency distribution for the no-new-standards case (which yields a shipment-weighted average efficiency) for the year of anticipated compliance with an amended or new standard. To project the trend in efficiency absent standards for circulator pumps over the entire shipments projection period, DOE followed the approach discussed in section IV.F.8 of this document. The

[53] Type of Heating System Used in New Single-Family Houses Completed. Available at *https://www.census.gov/construction/chars/xls/heatsystem_cust.xls* (Last accessed July 7, 2022).

[54] The NIA accounts for impacts in the 50 states and U.S. territories.

approach is further described in chapter 8 of the NOPR TSD.

For the standards cases, DOE used a ''roll-up'' scenario to establish the shipment-weighted efficiency for the year that standards are assumed to become effective (2026). In this scenario, the market shares of products in the no-new-standards case that do not meet the standard under consideration would ''roll up'' to meet the new standard level, and the market share of products above the standard would remain unchanged.

2. National Energy Savings

The national energy savings analysis involves a comparison of national energy consumption of the considered products between each potential standards case (''TSL'') and the case with no new or amended energy conservation standards. DOE calculated the national energy consumption by multiplying the number of units (stock) of each product (by vintage or age) by the unit energy consumption (also by vintage). DOE calculated annual NES based on the difference in national energy consumption for the no-new standards case and for each higher efficiency standard case. DOE estimated energy consumption and savings based on site energy and converted the electricity consumption and savings to primary energy (*i.e.,* the energy consumed by power plants to generate site electricity) using annual conversion factors derived from *AEO2022.* Cumulative energy savings are the sum of the NES for each year over the timeframe of the analysis.

Use of higher-efficiency equipment is occasionally associated with a direct rebound effect, which refers to an increase in utilization of the product due to the increase in efficiency. DOE did not find any data on the rebound effect specific to circulator pumps, and therefore did not apply a rebound effect in the calculation of the NES and the NPV.

DOE requests comment on the rebound effect specifically for circulator pumps, including the magnitude of any rebound effect and data sources specific to circulator pumps.

In 2011, in response to the recommendations of a committee on ''Point-of-Use and Full-Fuel-Cycle Measurement Approaches to Energy Efficiency Standards'' appointed by the National Academy of Sciences, DOE announced its intention to use FFC measures of energy use and greenhouse gas and other emissions in the national impact analyses and emissions analyses included in future energy conservation standards rulemakings. 76 FR 51281 (Aug. 18, 2011). After evaluating the approaches discussed in the August 18, 2011 notice, DOE published a statement of amended policy in which DOE explained its determination that EIA's National Energy Modeling System (''NEMS'') is the most appropriate tool for its FFC analysis and its intention to use NEMS for that purpose. 77 FR 49701 (Aug. 17, 2012). NEMS is a public domain, multi-sector, partial equilibrium model of the U.S. energy sector [55] that EIA uses to prepare its *Annual Energy Outlook.* The FFC factors incorporate losses in production and delivery in the case of natural gas (including fugitive emissions) and additional energy used to produce and deliver the various fuels used by power plants. The approach used for deriving FFC measures of energy use and emissions is described in appendix 10B of the NOPR TSD.

3. Net Present Value Analysis

The inputs for determining the NPV of the total costs and benefits experienced by consumers are (1) total annual installed cost, (2) total annual operating costs (energy costs and repair and maintenance costs), and (3) a discount factor to calculate the present value of costs and savings. DOE calculates net savings each year as the difference between the no-new-standards case and each standards case in terms of total savings in operating costs versus total increases in installed costs. DOE calculates operating cost savings over the lifetime of each product shipped during the projection period.

Due to lack of historical price data and uncertainty on the factors that may affect future circulator pump prices, DOE assumed a constant price (in $2021) when estimating circulator pump prices in future years.

The operating cost savings are energy cost savings and costs associated with repair and maintenance, which are calculated using the estimated operating cost savings in each year and the projected price of the appropriate form of energy. To estimate energy prices in future years, DOE multiplied the average regional energy prices by the projection of annual national-average commercial and residential energy price changes in the Reference case from *AEO2022,* which has an end year of 2050. To estimate price trends after 2050, DOE used the average annual rate of change in prices from 2020 through 2050. As part of the NIA, DOE also analyzed scenarios that used inputs from variants of the *AEO2022* Reference case that have lower and higher economic growth. Those cases have lower and higher energy price trends compared to the Reference case. NIA results based on these cases are presented in appendix 10C of the NOPR TSD.

In calculating the NPV, DOE multiplies the net savings in future years by a discount factor to determine their present value. For this NOPR, DOE estimated the NPV of consumer benefits using both a 3-percent and a 7-percent real discount rate. DOE uses these discount rates in accordance with guidance provided by the Office of Management and Budget (''OMB'') to Federal agencies on the development of regulatory analysis.[56] The discount rates for the determination of NPV are in contrast to the discount rates used in the LCC analysis, which are designed to reflect a consumer's perspective. The 7-percent real value is an estimate of the average before-tax rate of return to private capital in the U.S. economy. The 3-percent real value represents the ''social rate of time preference,'' which is the rate at which society discounts future consumption flows to their present value.

I. Consumer Subgroup Analysis

In analyzing the potential impact of new or amended energy conservation standards on consumers, DOE evaluates the impact on identifiable subgroups of consumers that may be disproportionately affected by a new or amended national standard. The purpose of a subgroup analysis is to determine the extent of any such disproportional impacts. DOE evaluates impacts on particular subgroups of consumers by analyzing the LCC impacts and PBP for those particular consumers from alternative standard levels. For this NOPR, DOE analyzed the impacts of the considered standard levels on senior-only households. The analysis used subsets of the RECS 2015 sample composed of households that meet the criteria for seniors. DOE used the LCC and PBP model to estimate the impacts of the considered efficiency levels on seniors. Chapter 11 in the NOPR TSD describes the consumer subgroup analysis.

[55] For more information on NEMS, refer to *The National Energy Modeling System: An Overview 2009,* DOE/EIA–0581(2009), October 2009. Available at *www.eia.gov/forecasts/aeo/index.cfm* (last accessed July 7, 2022).

[56] United States Office of Management and Budget. *Circular A–4: Regulatory Analysis.* September 17, 2003. *https://www.whitehouse.gov/wp-content/uploads/legacy_drupal_files/omb/circulars/A4/a-4.pdf* (last accessed July 3, 2022).

J. Manufacturer Impact Analysis

1. Overview

DOE performed an MIA to estimate the financial impacts of energy conservation standards on manufacturers of circulator pumps and to estimate the potential impacts of such standards on employment and manufacturing capacity. The MIA has both quantitative and qualitative aspects and includes analyses of projected industry cash flows, the INPV, investments in research and development (''R&D'') and manufacturing capital, and domestic manufacturing employment. Additionally, the MIA seeks to determine how energy conservation standards might affect manufacturing employment, capacity, and competition, as well as how standards contribute to overall regulatory burden. Finally, the MIA serves to identify any disproportionate impacts on manufacturer subgroups, including small business manufacturers.

The quantitative part of the MIA primarily relies on the Government Regulatory Impact Model (''GRIM''), an industry cash flow model with inputs specific to this rulemaking. The key GRIM inputs include data on the industry cost structure, unit production costs, product shipments, manufacturer markups, and investments in R&D and manufacturing capital required to produce compliant products. The key GRIM outputs are the INPV, which is the sum of industry annual cash flows over the analysis period, discounted using the industry-weighted average cost of capital, and the impact to domestic manufacturing employment. The model uses standard accounting principles to estimate the impacts of more-stringent energy conservation standards on a given industry by comparing changes in INPV and domestic manufacturing employment between a no-new-standards case and the various standards cases (*i.e.,* TSLs). To capture the uncertainty relating to manufacturer pricing strategies following standards, the GRIM estimates a range of possible impacts under different markup scenarios.

The qualitative part of the MIA addresses manufacturer characteristics and market trends. Specifically, the MIA considers such factors as a potential standard's impact on manufacturing capacity, competition within the industry, the cumulative impact of other DOE and non-DOE regulations, and impacts on manufacturer subgroups. The complete MIA is outlined in chapter 12 of the NOPR TSD.

DOE conducted the MIA for this rulemaking in three phases. In Phase 1 of the MIA, DOE prepared a profile of the circulator pump manufacturing industry based on the market and technology assessment and publicly available information. This included a top-down analysis of circulator pump manufacturers that DOE used to derive preliminary financial inputs for the GRIM (*e.g.,* revenues; materials, labor, overhead, and depreciation expenses; selling, general, and administrative expenses (''SG&A''); and R&D expenses). DOE also used public sources of information to further calibrate its initial characterization of the circulator pump manufacturing industry, including company filings of form 10–K from the SEC, [57] corporate annual reports, the U.S. Census Bureau's *Economic Census,* [58] and reports from D&B Hoovers.[59]

In Phase 2 of the MIA, DOE prepared a framework industry cash-flow analysis to quantify the potential impacts of energy conservation standards. The GRIM uses several factors to determine a series of annual cash flows starting with the announcement of the standard and extending over a 30-year period following the compliance date of the standard. These factors include annual expected revenues, costs of sales, SG&A and R&D expenses, taxes, and capital expenditures. In general, energy conservation standards can affect manufacturer cash flow in three distinct ways: (1) creating a need for increased investment, (2) raising production costs per unit, and (3) altering revenue due to higher per-unit prices and changes in sales volumes.

In addition, during Phase 2, DOE developed interview guides to distribute to manufacturers of circulator pumps in order to develop other key GRIM inputs, including product and capital conversion costs, and to gather additional information on the anticipated effects of energy conservation standards on revenues, direct employment, capital assets, industry competitiveness, and subgroup impacts.

In Phase 3 of the MIA, DOE conducted structured, detailed interviews (*i.e.,* 2016 and 2022 manufacturer interviews) with representative manufacturers. During these interviews, DOE discussed engineering, manufacturing, procurement, and financial topics to validate assumptions used in the GRIM and to identify key issues or concerns. See section IV.J.3 of this document for a description of the key issues raised by manufacturers during the interviews. As part of Phase 3, DOE also evaluated subgroups of manufacturers that may be disproportionately impacted by standards or that may not be accurately represented by the average cost assumptions used to develop the industry cash flow analysis. Such manufacturer subgroups may include small business manufacturers, low-volume manufacturers (''LVMs''), niche players, and/or manufacturers exhibiting a cost structure that largely differs from the industry average. DOE identified one subgroup for a separate impact analysis: small business manufacturers. The small business subgroup is discussed in section VI.B, ''Review under the Regulatory Flexibility Act'' and in chapter 12 of the NOPR TSD.

2. Government Regulatory Impact Model and Key Inputs

DOE uses the GRIM to quantify the changes in cash flow due to standards that result in a higher or lower industry value. The GRIM uses a standard, annual discounted cash-flow analysis that incorporates manufacturer costs, markups, shipments, and industry financial information as inputs. The GRIM models changes in costs, distribution of shipments, investments, and manufacturer margins that could result from an energy conservation standard. The GRIM spreadsheet uses the inputs to arrive at a series of annual cash flows, beginning in 2022 (the base year of the analysis) and continuing to 2055. DOE calculated INPVs by summing the stream of annual discounted cash flows during this period. For manufacturers of circulator pumps, DOE used a real discount rate of 9.6 percent, which was derived from industry financials and then modified according to feedback received during manufacturer interviews.

The GRIM calculates cash flows using standard accounting principles and compares changes in INPV between the no-new-standards case and each standards case. The difference in INPV between the no-new-standards case and a standards case represents the financial impact of the energy conservation standard on manufacturers. As discussed previously, DOE developed critical GRIM inputs using a number of sources, including publicly available

[57] U.S. Securities and Exchange Commission, Annual 10–K Reports (Various Years) available at *sec.gov* (Last accessed June 15th, 2022).

[58] U.S. Census Bureau, 2018–2020 Annual Survey of Manufacturers: Statistics for Industry Groups and Industries (2021) available at *www.census.gov/programs-surveys/asm.html* (Last accessed June 15th, 2022).

[59] D&B Hoovers available at *www.dnb.com* (Last Accessed June 15th, 2022).

data, results of the engineering analysis, and information gathered from industry stakeholders during the course of manufacturer interviews and subsequent Working Group meetings. The GRIM results are presented in section V.B.2. Additional details about the GRIM, the discount rate, and other financial parameters can be found in chapter 12 of the NOPR TSD.

a. Manufacturer Production Costs

Manufacturing more efficient equipment is typically more expensive than manufacturing baseline equipment due to the use of more complex components, which are typically more costly than baseline components. The changes in the MPCs of covered equipment can affect the revenues, gross margins, and cash flow of the industry. MPCs were derived in the engineering analysis, using methods discussed in section IV.C.3 of this document. For a complete description of the MPCs, see chapter 5 of the NOPR TSD.

b. Shipments Projections

The GRIM estimates manufacturer revenues based on total unit shipment projections and the distribution of those shipments by efficiency level. Changes in sales volumes and efficiency mix over time can significantly affect manufacturer finances. For this analysis, the GRIM uses the NIA's annual shipment projections derived from the shipments analysis from 2022 (the base year) to 2055 (the end year of the analysis period). See chapter 9 of the NOPR TSD for additional details.

c. Product and Capital Conversion Costs

Energy conservation standards could cause manufacturers to incur conversion costs to bring their production facilities and equipment designs into compliance. DOE evaluated the level of conversion-related expenditures that would be needed to comply with each considered efficiency level in each product class. For the MIA, DOE classified these conversion costs into two major groups: (1) product conversion costs; and (2) capital conversion costs. Product conversion costs are investments in research, development, testing, marketing, and other non-capitalized costs necessary to make product designs comply with energy conservation standards. Capital conversion costs are investments in property, plant, and equipment necessary to adapt or change existing production facilities such that new compliant product designs can be fabricated and assembled. Due to differences in design and manufacturing processes, DOE evaluated conversion costs by circular pump variety: CP1, CP2, and CP3.

To evaluate the level of product conversion costs manufacturers would likely incur to comply with energy conservation standards, DOE estimated the number of basic models that manufacturers would have to re-design to move their equipment lines to each incremental efficiency level. DOE developed the product conversion costs by estimating the amount of labor per basic model manufacturers would need for research and development to raise the efficiency of models to each incremental efficiency level. DOE anticipates that manufacturer basic model counts would decrease with use of ECMs due to the greater range of applications served by one ECM as opposed to an induction motor. DOE also assumed manufacturers would incur testing costs to establish certified ratings using DOE's test procedure for circulator pumps and applying DOE's statistical sampling plans to assess compliance.

For circulator pumps, DOE estimated the re-design effort varies by efficiency level. At EL 1, DOE anticipates a minor redesign effort as manufacturers increase their breadth of offerings to meet a standard at this level. DOE estimated a redesign effort of 18 months of engineering labor and 9 months of technician labor per model at this level. At EL 2, DOE anticipates manufacturers to integrate ECMs into their circulator pumps. This requires a significant amount of re-design as manufacturers transition from legacy AC induction motors to ECMs. DOE estimated a redesign effort of 35 months of engineering labor and 18 months of technician labor per model. At EL 3 and EL 4, DOE anticipates manufacturers to incur additional control board redesign costs as manufacturers add controls (*e.g.,* proportional pressure controls). DOE estimated a redesign effort of 54 months of engineering labor and 35 months of technician labor per model at EL 3. DOE estimated a redesign effort of 54 months of engineering labor and 54 months of technician labor per model at EL 4.

To evaluate the level of capital conversion costs manufacturers would likely incur to comply with energy conservation standards, DOE used information derived from the engineering analysis, shipments analysis, and manufacturer interviews. DOE used the information to estimate the additional investments in property, plant, and equipment that are necessary to meet energy conservation standards. In the engineering analysis evaluation of higher efficiency equipment from leading manufacturers of circulator pumps, DOE found a range of designs and manufacturing approaches. DOE attempted to account for both the range of manufacturing pathways and the current efficiency distribution of shipments in the modeling of industry capital conversion costs.

For all circulator pump varieties, DOE estimates capital conversion costs are driven by the cost for industry to expand production capacity at efficiency levels requiring use of an ECM (*i.e.,* EL 2, EL 3, and EL 4). DOE anticipates capital investments to be similar among EL 2 through EL 4 as circulator pump controls are likely to be used to increase a circulator pump beyond EL 2 and pump controls do not require additional capital investments. At all ELs, DOE anticipates manufacturers will incur costs to expand production capacity of more efficient equipment.

For CP1 type circular pumps, DOE anticipates manufacturers would choose to assemble ECMs in-house. As such, the capital conversion cost estimates for CP1 type circulator pumps include, but were not limited to, capital investments in welding and bobbin tooling, magnetizers, winders, lamination dies, testing equipment, and additional manufacturing floor space requirements.

For CP2 and CP3 type circular pumps, DOE anticipates manufacturers would purchase ECMs as opposed to assembling in-house. As such, DOE estimated the design changes to produce circulator pumps with ECMs would be driven by purchased parts (*i.e.,* ECMs). The capital conversion costs for these variety of circulator pumps are based on additional manufacturing floor space requirements to expand manufacturing capacity of ECMs.

In general, DOE assumes all conversion-related investments occur between the year of publication of the final rule and the year by which manufacturers must comply with the new standard. The conversion cost figures used in the GRIM can be found in Table IV.13 and section V.B.2 of this document. For additional information on the estimated capital and product conversion costs, see chapter 12 of the NOPR TSD.

TABLE IV.13—INDUSTRY PRODUCT AND CAPITAL CONVERSION COSTS PER EFFICIENCY LEVEL

	Units	Efficiency level			
		EL1	EL2	EL3	EL4
EL 1	EL 2	EL 3	EL 4		
Product Conversion Costs	2021$ millions	5.4	54.7	88.8	89.5
Capital Conversion Costs	2021$ millions	0.0	22.3	22.3	22.3

DOE seeks input on its estimates of product and capital conversion costs associated with manufacturing circulator pumps at the potential energy conservation standard.

d. Markup Scenarios

MSPs include direct manufacturing production costs (*i.e.,* labor, materials, and overhead estimated in DOE's MPCs) and all non-production costs (*i.e.,* SG&A, R&D, and interest), along with profit. To calculate the MSPs in the GRIM, DOE applied non-production cost markups to the MPCs estimated in the engineering analysis for each product class and efficiency level. Modifying these markups in the standards case yields different sets of impacts on manufacturers. For the MIA, DOE modeled two standards-case markup scenarios to represent uncertainty regarding the potential impacts on prices and profitability for manufacturers following the implementation of energy conservation standards: (1) a preservation of manufacturer markup scenario; and (2) a preservation of per-unit operating profit markup scenario. These scenarios lead to different markup values that, when applied to the MPCs, result in varying revenue and cash flow impacts.

Under the preservation of manufacturer markup scenario, DOE applied a single uniform manufacturer markup across all efficiency levels for each circulator variety, which assumes that manufacturers would be able to maintain the same amount of profit as a percentage of revenues at all efficiency levels. As MPCs increase with efficiency, this scenario implies that the absolute dollar markup will increase.

To estimate the average manufacturer markup used in the preservation of manufacturer markup scenario, DOE analyzed publicly available financial information for manufacturers of circulator pump equipment. DOE then requested feedback on its initial markup estimates during manufacturer interviews. The revised markups, which are used in DOE's quantitative analysis of industry financial impacts, are presented in Table IV.14. These markups capture all non-production costs, including SG&A expenses, R&D expenses, interest expenses, and profit.

TABLE IV.14—MANUFACTURER MARKUPS FOR PRESERVATION OF MANUFACTURER MARKUP SCENARIO

Circulator pump variety	Manufacturer markup
CP1	1.60
CP2	2.30
CP3	1.90

Under the preservation of per-unit operating profit markup scenario, DOE modeled a situation in which manufacturers are not able to increase per-unit operating profit in proportion to increases in manufacturer production costs. In this scenario, manufacturer markups are set so that operating profit one year after the compliance date of energy conservation standards is the same as in the no-new-standards case on a per-unit basis. In other words, manufacturers are not able to garner additional operating profit from the higher production costs and the investments that are required to comply with the standards; however, they are able to maintain the same per-unit operating profit in the standards case that was earned in the no-new-standards case. Therefore, operating margin in percentage terms is reduced between the no-new-standards case and standards case.

A comparison of industry financial impacts under the two markup scenarios is presented in section V.B.2 of this document.

3. Manufacturer Interviews

Throughout the rulemaking process, DOE has sought and continues to seek feedback and insight from interested parties that would improve the information in this process. DOE interviewed manufacturers as part of the NOPR analysis. In interviews, DOE asked manufacturers to describe their major concerns regarding this rulemaking. The following section highlights manufacturer concerns that helped inform the projected potential impacts of energy conservation standards on the industry. Manufacturer interviews are conducted under non-disclosure agreements ("NDAs"), so DOE does not document these discussions in the same way that it does public comments in the comment summaries and DOE's responses throughout the rest of this document. This section includes a list of the key issues manufacturers identified during the interview process.

a. Cost Increases and Component Shortages

Manufacturers highlighted difficulties in procurement of parts and purchased assemblies. Manufacturers noted that increases in raw material prices, escalating shipping and transportation costs, and limited component availability over the last two years affect manufacturer production costs. As a result, manufacturers were concerned that cost estimates based on historic 5-year averages would underestimate current production costs.

b. Motor Availability

Some manufacturers raised concerns that there could be procurement issues associated with a standard necessitating the use of an ECM. Manufacturers noted that there are few ECM suppliers. Additionally, manufacturers noted that there is less ECM variety compared to induction motors, and this could add additional complexities to researching and developing circulator pumps with properly sized ECMs. This issue is particularly exacerbated for CP2 and CP3 varieties where manufacturers indicated they may be more inclined to purchase ECMs as opposed to manufacturing in-house.

c. Timing of Standard

Some manufacturers emphasized that significant engineering and development resources would be required to transition to a standard requiring use of an ECM. Specifically, manufacturers noted that any transition to a standard requiring an ECM would need to be timed to accommodate the research and design of a full portfolio of circulator pumps to fit all applications while serving current market needs. As noted in discussed in detail in section III.G, this NOPR is proposing to adopt a 2-year compliance date for energy conservation standards; however, DOE may also consider a 3-year compliance date.

K. Emissions Analysis

The emissions analysis consists of two components. The first component estimates the effect of potential energy conservation standards on power sector and site (where applicable) combustion emissions of CO_2, NO_X, SO_2, and Hg. The second component estimates the impacts of potential standards on emissions of two additional greenhouse gases, CH_4 and N_2O, as well as the reductions to emissions of other gases due to ''upstream'' activities in the fuel production chain. These upstream activities comprise extraction, processing, and transporting fuels to the site of combustion.

The analysis of electric power sector emissions of CO_2, NO_X, SO_2, and Hg uses emissions factors intended to represent the marginal impacts of the change in electricity consumption associated with amended or new standards. The methodology is based on results published for the *AEO,* including a set of side cases that implement a variety of efficiency-related policies. The methodology is described in appendix 13A in the NOPR TSD. The analysis presented in this notice uses projections from *AEO2022*. Power sector emissions of CH_4 and N_2O from fuel combustion are estimated using Emission Factors for Greenhouse Gas Inventories published by the Environmental Protection Agency (EPA).[60]

FFC upstream emissions, which include emissions from fuel combustion during extraction, processing, and transportation of fuels, and ''fugitive'' emissions (direct leakage to the atmosphere) of CH_4 and CO_2, are estimated based on the methodology described in chapter 15 of the NOPR TSD.

The emissions intensity factors are expressed in terms of physical units per MWh or MMBtu of site energy savings. For power sector emissions, specific emissions intensity factors are calculated by sector and end use. Total emissions reductions are estimated using the energy savings calculated in the national impact analysis.

1. Air Quality Regulations Incorporated in DOE's Analysis

DOE's no-new-standards case for the electric power sector reflects the *AEO,* which incorporates the projected impacts of existing air quality regulations on emissions. *AEO2022* generally represents current legislation and environmental regulations, including recent government actions, that were in place at the time of preparation of *AEO2022,* including the emissions control programs discussed in the following paragraphs.[61]

SO_2 emissions from affected electric generating units (''EGUs'') are subject to nationwide and regional emissions cap-and-trade programs. Title IV of the Clean Air Act sets an annual emissions cap on SO_2 for affected EGUs in the 48 contiguous States and the District of Columbia (DC). (42 U.S.C. 7651 *et seq.*) SO_2 emissions from numerous States in the eastern half of the United States are also limited under the Cross-State Air Pollution Rule (''CSAPR''). 76 FR 48208 (Aug. 8, 2011). CSAPR requires these States to reduce certain emissions, including annual SO_2 emissions, and went into effect as of January 1, 2015.[62] *AEO2022* incorporates implementation of CSAPR, including the update to the CSAPR ozone season program emission budgets and target dates issued in 2016. 81 FR 74504 (Oct. 26, 2016). Compliance with CSAPR is flexible among EGUs and is enforced through the use of tradable emissions allowances. Under existing EPA regulations, any excess SO_2 emissions allowances resulting from the lower electricity demand caused by the adoption of an efficiency standard could be used to permit offsetting increases in SO_2 emissions by another regulated EGU.

However, beginning in 2016, SO_2 emissions began to fall as a result of the Mercury and Air Toxics Standards (''MATS'') for power plants. 77 FR 9304 (Feb. 16, 2012). In the MATS final rule, EPA established a standard for hydrogen chloride as a surrogate for acid gas hazardous air pollutants (''HAP''), and also established a standard for SO_2 (a non-HAP acid gas) as an alternative equivalent surrogate standard for acid gas HAP. The same controls are used to reduce HAP and non-HAP acid gas; thus, SO_2 emissions are being reduced as a result of the control technologies installed on coal-fired power plants to comply with the MATS requirements for acid gas. In order to continue operating, coal power plants must have either flue gas desulfurization or dry sorbent injection systems installed. Both technologies, which are used to reduce acid gas emissions, also reduce SO_2 emissions. Because of the emissions reductions under the MATS, it is unlikely that excess SO_2 emissions allowances resulting from the lower electricity demand would be needed or used to permit offsetting increases in SO_2 emissions by another regulated EGU. Therefore, energy conservation standards that decrease electricity generation would generally reduce SO_2 emissions. DOE estimated SO_2 emissions reduction using emissions factors based on *AEO2022.*

CSAPR also established limits on NO_X emissions for numerous States in the eastern half of the United States. Energy conservation standards would have little effect on NO_X emissions in those States covered by CSAPR emissions limits if excess NO_X emissions allowances resulting from the lower electricity demand could be used to permit offsetting increases in NO_X emissions from other EGUs. In such case, NO_X emissions would remain near the limit even if electricity generation goes down. A different case could possibly result, depending on the configuration of the power sector in the different regions and the need for allowances, such that NO_X emissions might not remain at the limit in the case of lower electricity demand. In this case, energy conservation standards might reduce NO_X emissions in covered States. Despite this possibility, DOE has chosen to be conservative in its analysis and has maintained the assumption that standards will not reduce NO_X emissions in States covered by CSAPR. Energy conservation standards would be expected to reduce NO_X emissions in the States not covered by CSAPR. DOE used *AEO2022* data to derive NO_X

[60] Available at *www.epa.gov/sites/production/files/2021-04/documents/emission-factors_apr2021.pdf* (last accessed July 12, 2021).

[61] For further information, see the Assumptions to *AEO2022* report that sets forth the major assumptions used to generate the projections in the Annual Energy Outlook. Available at *www.eia.gov/outlooks/aeo/assumptions/* (last accessed June 21, 2022).

[62] CSAPR requires states to address annual emissions of SO_2 and NO_X, precursors to the formation of fine particulate matter ($PM_{2.5}$) pollution, in order to address the interstate transport of pollution with respect to the 1997 and 2006 $PM_{2.5}$ National Ambient Air Quality Standards (''NAAQS''). CSAPR also requires certain states to address the ozone season (May-September) emissions of NO_X, a precursor to the formation of ozone pollution, in order to address the interstate transport of ozone pollution with respect to the 1997 ozone NAAQS. 76 FR 48208 (Aug. 8, 2011). EPA subsequently issued a supplemental rule that included an additional five states in the CSAPR ozone season program; 76 FR 80760 (Dec. 27, 2011) (Supplemental Rule), and EPA issued the CSAPR Update for the 2008 ozone NAAQS. 81 FR 74504 (Oct. 26, 2016).

1 In Sept. 2019, the D.C. Court of Appeals remanded the 2016 CSAPR Update to EPA. In April 2021, EPA finalized the 2021 CSAPR Update which resolved the interstate transport obligations of 21 states for the 2008 ozone NAAQS. 86 FR 23054 (April 30, 2021); *see also,* 86 FR 29948 (June 4, 2021) (correction to preamble). The 2021 CSAPR Update became effective on June 29, 2021.

emissions factors for the group of States not covered by CSAPR.

The MATS limit mercury emissions from power plants, but they do not include emissions caps and, as such, DOE's energy conservation standards would be expected to slightly reduce Hg emissions. DOE estimated mercury emissions reduction using emissions factors based on *AEO2022,* which incorporates the MATS.

L. Monetizing Emissions Impacts

As part of the development of this proposed rule, for the purpose of complying with the requirements of Executive Order 12866, DOE considered the estimated monetary benefits from the reduced emissions of CO_2, CH_4, N_2O, NO_X, and SO_2 that are expected to result from each of the TSLs considered. In order to make this calculation analogous to the calculation of the NPV of consumer benefit, DOE considered the reduced emissions expected to result over the lifetime of products shipped in the projection period for each TSL. This section summarizes the basis for the values used for monetizing the emissions benefits and presents the values considered in this NOPR.

On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087) granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and present monetized benefits where appropriate and permissible under law. DOE requests comment on how to address the climate benefits and other non-monetized effects of the proposal.

1. Monetization of Greenhouse Gas Emissions

DOE estimates the monetized benefits of the reductions in emissions of CO_2, CH_4, and N_2O by using a measure of the SC of each pollutant (*e.g.,* SC-CO_2). These estimates represent the monetary value of the net harm to society associated with a marginal increase in emissions of these pollutants in a given year, or the benefit of avoiding that increase. These estimates are intended to include (but are not limited to) climate-change-related changes in net agricultural productivity, human health, property damages from increased flood risk, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services.

DOE estimated the global social benefits of CO_2, CH_4, and N_2O reductions (*i.e.,* SC-GHGs) using the estimates presented in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990, published in February 2021 by the IWG. The SC-GHGs is the monetary value of the net harm to society associated with a marginal increase in emissions in a given year, or the benefit of avoiding that increase. In principle, SC-GHGs includes the value of all climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-GHGs therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton. The SC-GHGs is the theoretically appropriate value to use in conducting benefit-cost analyses of policies that affect CO_2, N_2O and CH4 emissions. As a member of the IWG involved in the development of the February 2021 SC-GHG TSD, DOE agrees that the interim SC-GHG estimates represent the most appropriate estimate of the SC-GHG until revised estimates have been developed reflecting the latest, peer-reviewed science.

The SC-GHGs estimates presented here were developed over many years, using transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. Specifically, in 2009, the IWG, that included the DOE and other executive branch agencies and offices was established to ensure that agencies were using the best available science and to promote consistency in the social cost of carbon (SC-CO_2) values used across agencies. The IWG published SC-CO_2 estimates in 2010 that were developed from an ensemble of three widely cited integrated assessment models (IAMs) that estimate global climate damages using highly aggregated representations of climate processes and the global economy combined into a single modeling framework. The three IAMs were run using a common set of input assumptions in each model for future population, economic, and CO_2 emissions growth, as well as equilibrium climate sensitivity—a measure of the globally averaged temperature response to increased atmospheric CO_2 concentrations. These estimates were updated in 2013 based on new versions of each IAM. In August 2016 the IWG published estimates of the social cost of methane (SC-CH_4) and nitrous oxide (SC-N_2O) using methodologies that are consistent with the methodology underlying the SC-CO_2 estimates. The modeling approach that extends the IWG SC-CO_2 methodology to non-CO_2 GHGs has undergone multiple stages of peer review. The SC-CH_4 and SC-N_2O estimates were developed by Marten *et al.*[63] and underwent a standard double-blind peer review process prior to journal publication. In 2015, as part of the response to public comments received to a 2013 solicitation for comments on the SC-CO_2 estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the SC-CO_2 estimates to offer advice on how to approach future updates to ensure that the estimates continue to reflect the best available science and methodologies. In January 2017, the National Academies released their final report, Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide, and recommended specific criteria for future updates to the SC-CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process (National Academies, 2017).[64] Shortly thereafter, in March 2017, President Trump issued Executive Order 13783, which disbanded the IWG, withdrew the previous TSDs, and directed agencies to ensure SC-CO_2 estimates used in regulatory analyses are consistent with the guidance contained in OMB's Circular A–4, ''including with respect to the consideration of domestic versus

[63] Marten, A. L., E. A. Kopits, C. W. Griffiths, S. C. Newbold, and A. Wolverton. Incremental CH4 and N2O mitigation benefits consistent with the US Government's SC-CO2 estimates. *Climate Policy.* 2015. 15(2): pp. 272–298.

[64] National Academies of Sciences, Engineering, and Medicine. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide.* 2017. The National Academies Press: Washington, DC.

international impacts and the consideration of appropriate discount rates'' (E.O. 13783, Section 5(c)). Benefit-cost analyses following E.O. 13783 used SC-GHG estimates that attempted to focus on the U.S.-specific share of climate change damages as estimated by the models and were calculated using two discount rates recommended by Circular A–4, 3 percent and 7 percent. All other methodological decisions and model versions used in SC-GHG calculations remained the same as those used by the IWG in 2010 and 2013, respectively.

On January 20, 2021, President Biden issued Executive Order 13990, which re-established the IWG and directed it to ensure that the U.S. Government's estimates of the social cost of carbon and other greenhouse gases reflect the best available science and the recommendations of the National Academies (2017). The IWG was tasked with first reviewing the SC-GHG estimates currently used in Federal analyses and publishing interim estimates within 30 days of the E.O. that reflect the full impact of GHG emissions, including by taking global damages into account. The interim SC-GHG estimates published in February 2021 are used here to estimate the climate benefits for this proposed rulemaking. The E.O. instructs the IWG to undertake a fuller update of the SC-GHG estimates by January 2022 that takes into consideration the advice of the National Academies (2017) and other recent scientific literature. The February 2021 SC-GHG TSD provides a complete discussion of the IWG's initial review conducted under E.O.13990. In particular, the IWG found that the SC-GHG estimates used under E.O. 13783 fail to reflect the full impact of GHG emissions in multiple ways.

First, the IWG found that the SC-GHG estimates used under E.O. 13783 fail to fully capture many climate impacts that affect the welfare of U.S. citizens and residents, and those impacts are better reflected by global measures of the SC-GHG. Examples of omitted effects from the E.O. 13783 estimates include direct effects on U.S. citizens, assets, and investments located abroad, supply chains, U.S. military assets and interests abroad, and tourism, and spillover pathways such as economic and political destabilization and global migration that can lead to adverse impacts on U.S. national security, public health, and humanitarian concerns. In addition, assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. A wide range of scientific and economic experts have emphasized the issue of reciprocity as support for considering global damages of GHG emissions. If the United States does not consider impacts on other countries, it is difficult to convince other countries to consider the impacts of their emissions on the United States. The only way to achieve an efficient allocation of resources for emissions reduction on a global basis—and so benefit the U.S. and its citizens—is for all countries to base their policies on global estimates of damages. As a member of the IWG involved in the development of the February 2021 SC-GHG TSD, DOE agrees with this assessment and, therefore, in this proposed rule DOE centers attention on a global measure of SC-GHG. This approach is the same as that taken in DOE regulatory analyses from 2012 through 2016. A robust estimate of climate damages that accrue only to U.S. citizens and residents does not currently exist in the literature. As explained in the February 2021 TSD, existing estimates are both incomplete and an underestimate of total damages that accrue to the citizens and residents of the U.S. because they do not fully capture the regional interactions and spillovers discussed above, nor do they include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature. As noted in the February 2021 SC-GHG TSD, the IWG will continue to review developments in the literature, including more robust methodologies for estimating a U.S.-specific SC-GHG value, and explore ways to better inform the public of the full range of carbon impacts. As a member of the IWG, DOE will continue to follow developments in the literature pertaining to this issue.

Second, the IWG found that the use of the social rate of return on capital (7 percent under current OMB Circular A–4 guidance) to discount the future benefits of reducing GHG emissions inappropriately underestimates the impacts of climate change for the purposes of estimating the SC-GHG. Consistent with the findings of the National Academies (2017) and the economic literature, the IWG continued to conclude that the consumption rate of interest is the theoretically appropriate discount rate in an intergenerational context,[65] and recommended that discount rate uncertainty and relevant aspects of intergenerational ethical considerations be accounted for in selecting future discount rates.

Furthermore, the damage estimates developed for use in the SC-GHG are estimated in consumption-equivalent terms, and so an application of OMB Circular A–4's guidance for regulatory analysis would then use the consumption discount rate to calculate the SC-GHG. DOE agrees with this assessment and will continue to follow developments in the literature pertaining to this issue. DOE also notes that while OMB Circular A–4, as published in 2003, recommends using 3 percent and 7 percent discount rates as ''default'' values, Circular A–4 also reminds agencies that ''different regulations may call for different emphases in the analysis, depending on the nature and complexity of the regulatory issues and the sensitivity of the benefit and cost estimates to the key assumptions.'' On discounting, Circular A–4 recognizes that ''special ethical considerations arise when comparing benefits and costs across generations,'' and Circular A–4 acknowledges that analyses may appropriately ''discount future costs and consumption benefits. . .at a lower rate than for intragenerational analysis.'' In the 2015 Response to Comments on the Social Cost of Carbon for Regulatory Impact Analysis, OMB, DOE, and the other IWG members recognized that ''Circular A–4 is a living document'' and ''the use of 7 percent is not considered appropriate for intergenerational discounting. There is wide support for this view in the academic literature, and it is recognized in Circular A–4 itself.'' Thus, DOE

[65] Interagency Working Group on Social Cost of Carbon. *Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866.* 2010. United States Government. (Last accessed April 15, 2022.) *www.epa.gov/sites/default/files/2016-12/documents/scc_tsd_2010.pdf;* Interagency Working Group on Social Cost of Carbon. *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.* 2013. (Last accessed April 15, 2022.) *www.federalregister.gov/documents/2013/11/26/2013-28242/technical-support-document-technical-update-of-the-social-cost-of-carbon-for-regulatory-impact;* Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. Technical Support Document: Technical Update on the Social Cost of Carbon for Regulatory Impact Analysis-Under Executive Order 12866. August 2016. (Last accessed January 18, 2022.) *www.epa.gov/sites/default/files/2016-12/documents/sc_co2_tsd_august_2016.pdf*; Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide. August 2016. (Last accessed January 18, 2022.) *www.epa.gov/sites/default/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf.*

concludes that a 7% discount rate is not appropriate to apply to value the social cost of greenhouse gases in the analysis presented in this analysis. In this analysis, to calculate the present and annualized values of climate benefits, DOE uses the same discount rate as the rate used to discount the value of damages from future GHG emissions, for internal consistency. That approach to discounting follows the same approach that the February 2021 TSD recommends ''to ensure internal consistency—*i.e.,* future damages from climate change using the SC-GHG at 2.5 percent should be discounted to the base year of the analysis using the same 2.5 percent rate.'' DOE has also consulted the National Academies' 2017 recommendations on how SC-GHG estimates can ''be combined in RIAs with other cost and benefits estimates that may use different discount rates.'' The National Academies reviewed ''several options,'' including ''presenting all discount rate combinations of other costs and benefits with SC-GHG estimates.''

As a member of the IWG involved in the development of the February 2021 SC-GHG TSD, DOE agrees with this assessment and will continue to follow developments in the literature pertaining to this issue. While the IWG works to assess how best to incorporate the latest, peer reviewed science to develop an updated set of SC-GHG estimates, it set the interim estimates to be the most recent estimates developed by the IWG prior to the group being disbanded in 2017. The estimates rely on the same models and harmonized inputs and are calculated using a range of discount rates. As explained in the February 2021 SC-GHG TSD, the IWG has recommended that agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates as were used in regulatory analyses between 2010 and 2016 and subject to public comment. For each discount rate, the IWG combined the distributions across models and socioeconomic emissions scenarios (applying equal weight to each) and then selected a set of four values recommended for use in benefit-cost analyses: an average value resulting from the model runs for each of three discount rates (2.5 percent, 3 percent, and 5 percent), plus a fourth value, selected as the 95th percentile of estimates based on a 3 percent discount rate. The fourth value was included to provide information on potentially higher-than-expected economic impacts from climate change. As explained in the February 2021 SC-GHG TSD, and DOE agrees, this update reflects the immediate need to have an operational SC-GHG for use in regulatory benefit-cost analyses and other applications that was developed using a transparent process, peer-reviewed methodologies, and the science available at the time of that process. Those estimates were subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013.

There are a number of limitations and uncertainties associated with the SC-GHG estimates. First, the current scientific and economic understanding of discounting approaches suggests discount rates appropriate for intergenerational analysis in the context of climate change are likely to be less than 3 percent, near 2 percent or lower.[66] Second, the IAMs used to produce these interim estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature and the science underlying their ''damage functions''—*i.e.,* the core parts of the IAMs that map global mean temperature changes and other physical impacts of climate change into economic (both market and nonmarket) damages—lags behind the most recent research. For example, limitations include the incomplete treatment of catastrophic and non-catastrophic impacts in the integrated assessment models, their incomplete treatment of adaptation and technological change, the incomplete way in which inter-regional and intersectoral linkages are modeled, uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the discount rate and uncertainty in economic growth over long time horizons. Likewise, the socioeconomic and emissions scenarios used as inputs to the models do not reflect new information from the last decade of scenario generation or the full range of projections. The modeling limitations do not all work in the same direction in terms of their influence on the SC-CO_2 estimates. However, as discussed in the February 2021 TSD, the IWG has recommended that, taken together, the limitations suggest that the interim SC-GHG estimates used in this final rule likely underestimate the damages from GHG emissions. DOE concurs with this assessment.

DOE's derivations of the SC-GHG (SC-CO_2, SC-N_2O, and SC-CH_4) values used for this NOPR are discussed in the following sections, and the results of DOE's analyses estimating the benefits of the reductions in emissions of these GHGs are presented in section V.B.6 of this document.

a. Social Cost of Carbon

The SC-CO_2 values used for this NOPR were generated using the values presented in the 2021 update from the IWG's February 2021 SC-GHG TSD. Table IV.15 shows the updated sets of SC-CO_2 estimates from the latest interagency update in 5-year increments from 2020 to 2050. The full set of annual values used is presented in Appendix 14–A of the NOPR TSD. For purposes of capturing the uncertainties involved in regulatory impact analysis, DOE has determined it is appropriate include all four sets of SC-CO_2 values, as recommended by the IWG.[67]

TABLE IV.15—ANNUAL SC-CO_2VALUES FROM 2021 INTERAGENCY UPDATE, 2020–2050

[2020$ per metric ton CO_2]

Year	Discount rate and statistic			
	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile
2020	14	51	76	152
2025	17	56	83	169

[66] Interagency Working Group on Social Cost of Greenhouse Gases (IWG). 2021. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. February. United States Government. Available at: <*https://www.whitehouse.gov/briefing-room/blog/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution/*.

[67] For example, the February 2021 TSD discusses how the understanding of discounting approaches suggests that discount rates appropriate for intergenerational analysis in the context of climate change may be lower than 3 percent.

TABLE IV.15—ANNUAL SC-CO_2 VALUES FROM 2021 INTERAGENCY UPDATE, 2020–2050—Continued

[2020$ per metric ton CO_2]

Year	Discount rate and statistic			
	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile
2030	19	62	89	187
2035	22	67	96	206
2040	25	73	103	225
2045	28	79	110	242
2050	32	85	116	260

In calculating the potential global benefits resulting from reduced CO_2 emissions, DOE used the values from the February 2021 SC-GHG TSD, adjusted to 2021$ using the implicit price deflator for gross domestic product (''GDP'') from the Bureau of Economic Analysis. DOE derived values from 2051 to 2070 based on estimates published by EPA.[68] These estimates are based on methods, assumptions, and parameters identical to the 2020–2050 estimates published by the IWG. DOE expects additional climate benefits to accrue for any longer-life circulator pumps after 2070, but a lack of available SC-CO_2 estimates for emissions years beyond 2070 prevents DOE from monetizing these potential benefits in this analysis. If further analysis of monetized climate benefits beyond 2070 becomes available prior to the publication of the final rule, DOE will include that analysis in the final rule.

DOE multiplied the CO_2 emissions reduction estimated for each year by the SC-CO_2 value for that year in each of the four cases. To calculate a present value of the stream of monetary values, DOE discounted the values in each of the four cases using the specific discount rate that had been used to obtain the SC-CO_2 values in each case.

b. Social Cost of Methane and Nitrous Oxide

The SC-CH_4 and SC-N_2O values used for this NOPR were generated using the values presented in the February 2021 SC-GHG TSD. Table IV.16 shows the updated sets of SC-CH_4 and SC-N_2O estimates from the latest interagency update in 5-year increments from 2020 to 2050. The full set of annual values used is presented in Appendix 14–A of the NOPR TSD. To capture the uncertainties involved in regulatory impact analysis, DOE has determined it is appropriate to include all four sets of SC-CH_4 and SC-N_2O values, as recommended by the IWG. DOE derived values after 2050 using the approach described above for the SC-CO_2.

TABLE IV.16—ANNUAL SC-CH_4 AND SC-N_2O VALUES FROM 2021 INTERAGENCY UPDATE, 2020–2050

[2020$ per metric ton]

Year	SC-CH_4				SC-N_2O			
	Discount rate and statistic				Discount rate and statistic			
	5%	3%	2.5%	3%	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile	Average	Average	Average	95th percentile
2020	670	1500	2000	3900	5800	18000	27000	48000
2025	800	1700	2200	4500	6800	21000	30000	54000
2030	940	2000	2500	5200	7800	23000	33000	60000
2035	1100	2200	2800	6000	9000	25000	36000	67000
2040	1300	2500	3100	6700	10000	28000	39000	74000
2045	1500	2800	3500	7500	12000	30000	42000	81000
2050	1700	3100	3800	8200	13000	33000	45000	88000

DOE multiplied the CH_4 and N_2O emissions reduction estimated for each year by the SC-CH_4 and SC-N_2O estimates for that year in each of the cases. To calculate a present value of the stream of monetary values, DOE discounted the values in each of the cases using the specific discount rate that had been used to obtain the SC-CH_4 and SC-N_2O estimates in each case.

2. Monetization of Other Emissions Impacts

For the NOPR, DOE estimated the monetized value of NO_X and SO_2 emissions reductions from electricity generation using the latest benefit per ton estimates for that sector from the EPA's Benefits Mapping and Analysis Program.[69] DOE used EPA's values for $PM_{2.5}$-related benefits associated with NO_X and SO_2 and for ozone-related benefits associated with NO_X for 2025 2030, and 2040, calculated with discount rates of 3 percent and 7 percent. DOE used linear interpolation to define values for the years not given in the 2025 to 2040 period; for years beyond 2040 the values are held constant. DOE derived values specific to the sector for circulator pumps using a

[68] See EPA, *Revised 2023 and Later Model Year Light-Duty Vehicle GHG Emissions Standards: Regulatory Impact Analysis,* Washington, DC, December 2021. Available at: *https://www.epa.gov/system/files/documents/2021-12/420r21028.pdf* (last accessed January 13, 2022).

[69] *Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 21 Sectors. www.epa.gov/benmap/estimating-benefit-ton-reducing-pm25-precursors-21-sectors.*

method described in appendix 14B of the NOPR TSD.

DOE multiplied the site emissions reduction (in tons) in each year by the associated $/ton values, and then discounted each series using discount rates of 3 percent and 7 percent as appropriate.

M. Utility Impact Analysis

The utility impact analysis estimates several effects on the electric power generation industry that would result from the adoption of new or amended energy conservation standards. The utility impact analysis estimates the changes in installed electrical capacity and generation that would result for each TSL. The analysis is based on published output from the NEMS associated with *AEO2022*. NEMS produces the *AEO* Reference case, as well as a number of side cases that estimate the economy-wide impacts of changes to energy supply and demand. For the current analysis, impacts are quantified by comparing the levels of electricity sector generation, installed capacity, fuel consumption and emissions in the *AEO2022* Reference case and various side cases. Details of the methodology are provided in the appendices to chapters 13 and 15 of the NOPR TSD.

The output of this analysis is a set of time-dependent coefficients that capture the change in electricity generation, primary fuel consumption, installed capacity and power sector emissions due to a unit reduction in demand for a given end use. These coefficients are multiplied by the stream of electricity savings calculated in the NIA to provide estimates of selected utility impacts of potential new or amended energy conservation standards.

N. Employment Impact Analysis

DOE considers employment impacts in the domestic economy as one factor in selecting a proposed standard. Employment impacts from new or amended energy conservation standards include both direct and indirect impacts. Direct employment impacts are any changes in the number of employees of manufacturers of the products subject to standards, their suppliers, and related service firms. The MIA addresses those impacts. Indirect employment impacts are changes in national employment that occur due to the shift in expenditures and capital investment caused by the purchase and operation of more-efficient appliances. Indirect employment impacts from standards consist of the net jobs created or eliminated in the national economy, other than in the manufacturing sector being regulated, caused by (1) reduced spending by consumers on energy, (2) reduced spending on new energy supply by the utility industry, (3) increased consumer spending on the products to which the new standards apply and other goods and services, and (4) the effects of those three factors throughout the economy.

One method for assessing the possible effects on the demand for labor of such shifts in economic activity is to compare sector employment statistics developed by the Labor Department's Bureau of Labor Statistics (''BLS''). BLS regularly publishes its estimates of the number of jobs per million dollars of economic activity in different sectors of the economy, as well as the jobs created elsewhere in the economy by this same economic activity. Data from BLS indicate that expenditures in the utility sector generally create fewer jobs (both directly and indirectly) than expenditures in other sectors of the economy.[70] There are many reasons for these differences, including wage differences and the fact that the utility sector is more capital-intensive and less labor-intensive than other sectors. Energy conservation standards have the effect of reducing consumer utility bills. Because reduced consumer expenditures for energy likely lead to increased expenditures in other sectors of the economy, the general effect of efficiency standards is to shift economic activity from a less labor-intensive sector (*i.e.,* the utility sector) to more labor-intensive sectors (*e.g.,* the retail and service sectors). Thus, the BLS data suggest that net national employment may increase due to shifts in economic activity resulting from energy conservation standards.

DOE estimated indirect national employment impacts for the standard levels considered in this NOPR using an input/output model of the U.S. economy called Impact of Sector Energy Technologies version 4 (''ImSET'').[71] ImSET is a special-purpose version of the ''U.S. Benchmark National Input-Output'' (''I–O'') model, which was designed to estimate the national employment and income effects of energy-saving technologies. The ImSET software includes a computer-based I–O model having structural coefficients that characterize economic flows among 187 sectors most relevant to industrial, commercial, and residential building energy use.

DOE notes that ImSET is not a general equilibrium forecasting model, and that the uncertainties involved in projecting employment impacts, especially changes in the later years of the analysis. Because ImSET does not incorporate price changes, the employment effects predicted by ImSET may over-estimate actual job impacts over the long run for this rule. Therefore, DOE used ImSET only to generate results for near-term timeframes (2026–2031), where these uncertainties are reduced. For more details on the employment impact analysis, see chapter 16 of the NOPR TSD.

O. Other Topics

a. Acceptance Test Grades

In response to the May 2021 RFI, China commented that in the context of discussing updates to industry standards, DOE had not provided pump test acceptance grades and corresponding tolerances. (China, No. 111 at p. 1) DOE interprets the comment to regard minimum energy conservation standards, as acceptance tests *per se* have not been discussed as part of this rulemaking process. Energy conservation standards, however, are proposed as part of this NOPR. The rationale for selecting the proposed standard level is discuss in section V.C.1 of this document.

V. Analytical Results and Conclusions

The following section addresses the results from DOE's analyses with respect to the considered energy conservation standards for circulator pumps. It addresses the TSLs examined by DOE, the projected impacts of each of these levels if adopted as energy conservation standards for circulator pumps, and the standards levels that DOE is proposing to adopt in this NOPR. Additional details regarding DOE's analyses are contained in the NOPR TSD supporting this document.

A. Trial Standard Levels

In general, DOE typically evaluates potential standards for products and equipment by grouping individual efficiency levels for each class into TSLs. Use of TSLs allows DOE to identify and consider manufacturer cost interactions between the equipment classes, to the extent that there are such interactions, and market cross elasticity from consumer purchasing decisions

[70] See U.S. Department of Commerce—Bureau of Economic Analysis. *Regional Multipliers: A User Handbook for the Regional Input-Output Modeling System (RIMS II).* 1997. U.S. Government Printing Office: Washington, DC. Available at *www.bea.gov/scb/pdf/regional/perinc/meth/rims2.pdf* (last accessed last accessed July 6, 2021).

[71] Livingston, O.V., S.R. Bender, M.J. Scott, and R.W. Schultz. *ImSET 4.0: Impact of Sector Energy Technologies Model Description and User Guide.* 2015. Pacific Northwest National Laboratory: Richland, WA. PNNL–24563.

that may change when different standard levels are set.

In the analysis conducted for this NOPR, DOE analyzed the benefits and burdens of four TSLs for circulator pumps. As discussed previously, because there is only one proposed equipment class for circulator pumps, DOE developed TSLs that align with their corresponding ELs (*i.e.,* TSL 1 corresponds to EL 1, etc). Table V.1 presents the TSLs and the corresponding efficiency levels that DOE has identified for potential energy conservation standards for circulator pumps. TSL 4 represents the maximum technologically feasible (''max-tech'') energy efficiency.

TABLE V.1—TRIAL STANDARD LEVELS FOR CIRCULATOR PUMPS BY EFFICIENCY LEVEL

TSL	EL
1	1
2	2
3	3
4	4

B. Economic Justification and Energy Savings

1. Economic Impacts on Individual Consumers

DOE analyzed the economic impacts on circulator pump consumers by looking at the effects that potential standards at each TSL would have on the LCC and PBP. DOE also examined the impacts of potential standards on selected consumer subgroups. These analyses are discussed in the following sections.

a. Life-Cycle Cost and Payback Period

In general, higher-efficiency products affect consumers in two ways: (1) purchase price increases and (2) annual operating costs decrease. Inputs used for calculating the LCC and PBP include total installed costs (*i.e.,* product price plus installation costs), and operating costs (*i.e.,* annual energy use, energy prices, energy price trends, repair costs, and maintenance costs). The LCC calculation also uses product lifetime and a discount rate. Chapter [8] of the NOPR TSD provides detailed information on the LCC and PBP analyses.

Table V.2 through Table V.3 show the LCC and PBP results for the TSLs considered for circulator pumps. In the table, the simple payback is measured relative to the baseline product. In the second table, impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (see section IV.F of this document). Because some consumers purchase products with higher efficiency in the no-new-standards case, the average savings are less than the difference between the average LCC of the baseline product and the average LCC at each TSL. The savings refer only to consumers who are affected by a standard at a given TSL. Those who already purchase a product with efficiency at or above a given TSL are not affected. Consumers for whom the LCC increases at a given TSL experience a net cost.

TABLE V.2—AVERAGE LCC AND PBP RESULTS FOR CIRCULATOR PUMPS

TSL	Efficiency level	Average costs (2021$)				Simple payback)years)	Average lifetime (years)
		Installed cost	First year's operating cost	Lifetime operating cost	LCC		
	Baseline	598.4	40.8	363.3	961.8		10.6
1	1	598.4	34.8	311.1	909.6	0.0	10.6
2	2	678.4	21.7	200.0	878.4	4.2	10.6
3	3	757.5	11.3	111.4	869.0	5.4	10.6
4	4	784.5	7.8	82.0	866.6	5.6	10.6

Note: The results for each TSL are calculated assuming that all consumers use products at that efficiency level. The PBP is measured relative to the baseline product.

TABLE V.3—AVERAGE LCC SAVINGS RELATIVE TO THE NO-NEW-STANDARDS CASE FOR CIRCULATOR PUMPS

TSL	Efficiency level	Life-cycle cost savings	
		Average LCC savings * ($2021)	Percent of consumers that experience net cost
1	1	125.2	0.0
2	2	103.2	29.2
3	3	105.3	46.4
4	4	97.6	49.7

* The savings represent the average LCC for affected consumers.

b. Consumer Subgroup Analysis

In the consumer subgroup analysis, DOE estimated the impact of the considered TSLs on senior-only households. Table V.4 compares the average LCC savings and PBP at each efficiency level for seniors with similar metrics for the entire consumer sample for circulator pumps. In most cases, the average LCC savings and PBP for senior-only households at the considered efficiency levels are not substantially different from the average for all households. Chapter 11 of the NOPR TSD presents the complete LCC and PBP results for the subgroups.

TABLE V.4—COMPARISON OF LCC SAVINGS AND PBP FOR SENIORS AND ALL CONSUMERS

TSL	Senior-only households	All consumers
Average LCC Savings (2021$)		
1	116.3	125.2
2	116.7	103.2
3	104.1	105.3
4	92.4	97.6
Payback Period (years)		
1	0	0
2	3.5	4.2
3	5.3	5.4
4	5.6	5.6

c. Rebuttable Presumption Payback

As discussed in section IV.F.9, EPCA establishes a rebuttable presumption that an energy conservation standard is economically justified if the increased purchase cost for a product that meets the standard is less than three times the value of the first-year energy savings resulting from the standard. In calculating a rebuttable presumption payback period for each of the considered TSLs, DOE used discrete values, and, as required by EPCA, based the energy use calculation on the DOE test procedure for circulator pumps. In contrast, the PBPs presented in section V.B.1.a were calculated using distributions that reflect the range of energy use in the field. Table V.5 presents the rebuttable-presumption payback periods for the considered TSLs for circulator pumps. While DOE examined the rebuttable-presumption criterion, it considered whether the standard levels considered for the NOPR are economically justified through a more detailed analysis of the economic impacts of those levels, pursuant to 42 U.S.C. 6295(o)(2)(B)(i), that considers the full range of impacts to the consumer, manufacturer, Nation, and environment. The results of that analysis serve as the basis for DOE to definitively evaluate the economic justification for a potential standard level, thereby supporting or rebutting the results of any preliminary determination of economic justification.

TABLE V.5—REBUTTABLE-PRESUMPTION PAYBACK PERIODS

TSL	Rebuttable PBP (years)
1	
2	2.8
3	4.2
4	4.5

2. Economic Impacts on Manufacturers

DOE performed an MIA to estimate the impact of energy conservation standards on manufacturers of circulator pumps. The following section describes the expected impacts on manufacturers at each considered TSL. Chapter 12 of the NOPR TSD explains the analysis in further detail.

a. Economic Impacts on Manufacturers

In this section, DOE provides GRIM results from the analysis, which examines changes in the industry that would result from a standard. The following tables summarize the estimated financial impacts (represented by changes in INPV) of potential energy conservation standards on manufacturers of circulator pumps, as well as the conversion costs that DOE estimates manufacturers of circulator pumps would incur at each TSL.

The impact of potential energy conservation standards was analyzed under two markup scenarios: (1) the preservation of manufacturer markup scenario and (2) the preservation of per-unit operating profit markup scenario, as discussed in section IV.C.5 of this document. The preservation of manufacturer markup scenario provides the upper bound while the preservation of operating profits scenario results in the lower (or more severe) bound to impacts of potential standards on industry.

Each of the modeled scenarios results in a unique set of cash flows and corresponding INPV for each TSL. INPV is the sum of the discounted cash flows to the industry from the base year through the end of the analysis period (2022–2055). The ''change in INPV'' results refer to the difference in industry value between the no-new-standards case and standards case at each TSL. To provide perspective on the short-run cash flow impact, DOE includes a comparison of free cash flow between the no-new-standards case and the standards case at each TSL in the year before standards would take effect. This figure provides an understanding of the magnitude of the required conversion costs relative to the cash flow generated by the industry.

Conversion costs are one-time investments for manufacturers to bring their manufacturing facilities and product designs into compliance with potential standards. As described in section IV.J.2.c of this document, conversion cost investments occur between the year of publication of the final rule and the year by which manufacturers must comply with the new standard. The conversion costs can have a significant impact on the short-term cash flow on the industry and generally result in lower free cash flow in the period between the publication of the final rule and the compliance date of potential standards. Conversion costs are independent of the manufacturer markup scenarios and are not presented as a range in this analysis.

The results in Table V.6 of this NOPR show potential INPV impacts for circulator pump manufacturers. The table presents the range of potential impacts reflecting both the less severe set of potential impacts (preservation of manufacturer markup) and the more severe set of potential impacts (preservation of per-unit operating profit). In the following discussion, the INPV results refer to the difference in industry value between the no-new-standards case and each standards case that results from the sum of discounted cash flows from 2022 (the base year) through 2055 (the end of the analysis period).

To provide perspective on the near-term cash flow impact, DOE discusses the change in free cash flow between the no-new-standards case and the standards case at each efficiency level in the year before new standards take effect. These figures provide an understanding of the magnitude of the required conversion costs at each TSL relative to the cash flow generated by the industry in the no-new-standards case.

TABLE V.6—MANUFACTURER IMPACT ANALYSIS FOR CIRCULATOR PUMPS

	Units	No-new-standards case	Trial standard level			
			1 *	2	3	4
INPV	2021$ millions	325.9	322.6	261.6–347.3	228.9–351.4	219.9–376.7
Change in INPV	2021$ millions		(3.2)	(64.3)–21.4	(97.0)–25.5	(106.0)–50.8
	%		(1.0)	(19.7)–6.6	(29.8)–7.8	(32.5)–15.6
Free Cash Flow (2025)	2021$ millions	25.6	23.3	(9.6)	(27.1)	(27.5)

TABLE V.6—MANUFACTURER IMPACT ANALYSIS FOR CIRCULATOR PUMPS—Continued

	Units	No-new-standards case	Trial standard level			
			1*	2	3	4
Change in Free Cash Flow	2021$ millions		(2.2)	(35.1)	(52.7)	(53.0)
	%		(8.8)	(137.5)	(206.0)	(207.5)
Product Conversion Costs	2021$ millions		5.4	54.7	88.8	89.5
Capital Conversion Costs	2021$ millions			22.3	22.3	22.3
Total Conversion Costs	2021$ millions		5.4	77.0	111.1	111.8

Note: Parenthesis indicate negative values.
* Both manufacturer markup scenarios for TSL 1 yield INPV impacts that are not differentiable at the granularity of this table. As such, these impacts are expressed as one value.

At TSL 1, DOE estimates INPV impacts for circulator pump manufacturers to decrease by 1 percent, or a decrease of $3.2 million. At this level, DOE estimates that industry free cash flow would decrease by approximately 8.8 percent to negative $2.2 million, compared to the no-new-standards-case value of $23.3 million in the year before compliance (2025).

DOE estimates 58 percent circulator pump shipments meet or exceed the efficiency standards at TSL 1. DOE does not expect the modest increases in efficiency requirements at this TSL to require large capital investments. DOE does anticipate manufacturers to make slight investments in R&D to re-design some of their equipment offering to meet a standard at this level. Overall, DOE estimates that manufacturers would incur $5.4 million in product conversion costs to bring their equipment portfolios into compliance with a standard set to TSL 1. At TSL 1, manufacturers have basic models that meet or exceed this efficiency level.

At TSL 1, the shipment-weighted average MPC for all circulator pumps does not change relative to the no-new-standards case shipment-weighted average MPC in 2026. Under the preservation of manufacturer markup scenario, DOE applies the same markup as the no-new-standards scenario allowing manufacturers to maintain the same amount of profit as a percentage of revenues (*i.e.,* as MPCs increase, the absolute dollar markup increases). However, because the shipment-weighted average MPC does not increase at TSL 1 compared to the no-new-standards case, manufacturers are unable recover the conversion cost investment through additional profit on equipment offerings. Under the preservation of per-unit operating profit markup scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or higher MPCs. Therefore, the $5.4 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 1 in both manufacturer markup scenarios.

At TSL 2, DOE estimates impacts on INPV for circulator pump manufacturers to range from a decrease of 19.7 percent to an increase of 6.6 percent, or a decrease of $64.3 million to an increase of $21.4 million. At this level, DOE estimates that industry free cash flow would decrease by approximately 137.5 percent to −$9.6 million, compared to the no-new-standards-case value of $25.6 million in the year before compliance (2025).

TSL 2 would set the energy conservation standard at EL 2 for all circulator pumps. DOE estimates 19 percent of circulator pump shipments meet or exceed the efficiency standards at TSL 2. Product and capital conversion costs would increase at this TSL as manufacturers update designs and production equipment to meet a standard that would likely require manufacturers to use ECMs. DOE anticipates manufacturers would need to make a significant investment to purchase production equipment to be able to produce ECMs in-house for CP1 variety. For CP2 and CP3 varieties, DOE anticipates that most manufacturers would choose to source ECMs from third parties resulting in a smaller level of investment of production equipment for these circulator pump varieties. DOE's capital conversion cost estimates include capital investments in welding and bobbin tooling, magnetizers, winders, lamination dies, testing equipment, and additional manufacturing floor space. DOE anticipates manufacturers to incur product conversion costs to redesign basic models to incorporate ECMs.

Overall, DOE estimates that manufacturers would incur $54.7 million in product conversion costs and $22.3 million in capital conversion costs to bring their equipment portfolios into compliance with a standard set to TSL 2. At TSL 2, capital and product conversion costs are a key driver of the decrease in free cash flow. These upfront investments result in a lower free cash flow in the year before the compliance date.

At TSL 2, the shipment-weighted average MPC for all circulator pumps increases by 43.7 percent relative to the no-new-standards case shipment-weighted average MPC in 2026. In the preservation of manufacturer markup scenario, manufacturers can fully pass on this significant cost increase to customers. In this manufacturer markup scenario, the additional revenue generated from the significant increase in shipment-weighted average MPC outweighs the $77.0 million in conversion costs, causing a positive change in INPV at TSL 2.

Under the preservation of per-unit operating profit markup scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or higher MPCs. In this scenario, the 43.7 percent shipment-weighted average MPC increase results in a reduction in the manufacturer markup after the analyzed compliance year. This reduction in the manufacturer markup and the $77.0 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 2 under the preservation of per-unit operating profit markup scenario.

At TSL 3, DOE estimates impacts on INPV for circulator pump manufacturers to range from a decrease of 29.8 percent to an increase of 7.8 percent, or a decrease of $97.0 million to an increase of $25.5 million. At this level, DOE estimates that industry free cash flow would decrease by approximately 206.0 percent to −$27.1 million, compared to the no-new-standards-case value of $25.6 million in the year before compliance (2025).

DOE estimates 12 percent of circulator pump base case shipments meet or exceed the efficiency standards at TSL

3. Product conversion costs would increase at this TSL as manufacturers improve designs to incorporate added controls necessitated at this TSL. DOE anticipates capital conversion costs to remain similar to those at TSL 2 as conversion costs are more representative of design changes.

Overall, DOE estimates that manufacturers would incur $88.8 million in product conversion costs and $22.3 million in capital conversion costs to bring their equipment portfolios into compliance with a standard set to TSL 3. At TSL 3, product conversion costs are a key driver of the decrease in free cash flow. These upfront investments result in a lower free cash flow in the year before the compliance date.

At TSL 3, the shipment-weighted average MPC for all circulator pumps increases by 60.7 percent relative to the no-new-standards case shipment-weighted average MPC in 2026. In the preservation of manufacturer markup scenario, manufacturers can fully pass on this significant cost increase to customers. In this manufacturer markup scenario, the additional revenue generated from the significant increase in shipment-weighted average MPC outweighs the $111.1 million in conversion costs, causing a positive change in INPV at TSL 3.

Under the preservation of per-unit operating profit markup scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or higher MPCs. In this scenario, the 60.7 percent shipment-weighted average MPC increase results in a reduction in the manufacturer markup after the analyzed compliance year. This reduction in the manufacturer markup and the $111.1 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 3 under the preservation of per-unit operating profit markup scenario.

At TSL 4, DOE estimates impacts on INPV for circulator pump manufacturers to range from a decrease of 32.5 percent to an increase of 15.6 percent, or a decrease of $106.0 million to an increase of $50.8 million. At this level, DOE estimates that industry free cash flow would decrease by approximately 207.5 percent to −$27.5 million, compared to the no-new-standards-case value of $25.6 million in the year before compliance (2025).

DOE estimates 2 percent of circulator pump base case shipments meet or exceed the efficiency standards at TSL 4. Product conversion costs would modestly increase at this TSL as manufacturers update designs to incorporate added controls. DOE anticipates capital conversion costs to remain similar to those at TSL 2 and TSL 3.

Overall, DOE estimates that manufacturers would incur $89.5 million in product conversion costs and $22.3 million in capital conversion costs to bring their equipment portfolios into compliance with a standard set to TSL 4. At TSL 4, product conversion costs continue to be a key driver of the decrease in free cash flow. These upfront investments result in a lower free cash flow in the year before the compliance date.

At TSL 4, the shipment-weighted average MPC for all circulator pumps increases by 75.8 percent relative to the no-new-standards case shipment-weighted average MPC in 2026. In the preservation of manufacturer markup scenario, manufacturers can fully pass on this significant cost increase to customers. In this manufacturer markup scenario, the additional revenue generated from the significant increase in shipment-weighted average MPC outweighs the $111.8 million in conversion costs, causing a positive change in INPV at TSL 4.

Under the preservation of per-unit operating profit markup scenario, manufacturers earn the same per-unit operating profit as would be earned in the no-new-standards case, but manufacturers do not earn additional profit from their investments or higher MPCs. In this scenario, the 75.8 percent shipment-weighted average MPC increase results in a reduction in the manufacturer markup after the analyzed compliance year. This reduction in the manufacturer markup and the $111.8 million in conversion costs incurred by manufacturers cause a negative change in INPV at TSL 4 under the preservation of per-unit operating profit markup scenario.

b. Direct Impacts on Employment

To quantitatively assess the potential impacts of energy conservation standards on direct employment in the circulator pump industry, DOE typically uses the GRIM to estimate the domestic labor expenditures and number of direct employees in the no-new-standards case and in each of the standards cases during the analysis period. This analysis includes both production and non-production employees employed by circulator pump manufacturers. DOE used statistical data from the U.S. Census Bureau's 2020 Annual Survey of Manufacturers [72] (''ASM''), the results of the engineering analysis, and interviews with manufacturers to determine the inputs necessary to calculate industry-wide labor expenditures and domestic employment levels. Labor expenditures related to manufacturing of the product are a function of the labor intensity of the product, the sales volume, and an assumption that wages remain fixed in real terms over time.

The total labor expenditures in the GRIM are converted to domestic production worker employment levels by dividing production labor expenditures by the average fully burden wage per production worker. DOE calculated the fully burdened wage by multiplying the industry production worker hourly blended wage (provided by the ASM) by the fully burdened wage ratio. The fully burdened wage ratio factors in paid leave, supplemental pay, insurance, retirement and savings, and legally required benefits. DOE determined the fully burdened ratio from the Bureau of Labor Statistic's employee compensation data.[73] The estimates of production workers in this section cover workers, including line-supervisors who are directly involved in fabricating and assembling a product within the manufacturing facility. Workers performing services that are closely associated with production operations, such as materials handling tasks using forklifts, are also included as production labor.

Non-production worker employment levels were determined by multiplying the industry ratio of production worker employment to non-production employment against the estimated production worker employment explained above. Estimates of non-production workers in this section cover above the line supervisors, sales, sales delivery, installation, office functions, legal, and technical employees.

The total direct employment impacts calculated in the GRIM are the sum of the changes in the number of domestic production and non-production workers resulting from the energy conservation standards for circulator pumps, as compared to the no-new-standards case. Typically, more efficient equipment is more complex and labor intensive to produce. Per-unit labor requirements and production time requirements trend

[72] U.S. Census Bureau, 2018–2020 Annual Survey of Manufacturers: Statistics for Industry Groups and Industries (2021) (Available at *www.census.gov/data/tables/time-series/econ/asm/2018-2020-asm.html*).

[73] U.S. Bureau of Labor Statistics. *Employer Costs for Employee Compensation.* June 16, 2022. Available at: *www.bls.gov/news.release/pdf/ecec.pdf.*

higher with more stringent energy conservation standards.

DOE estimates that 65 percent of circulator pumps sold in the United States are currently manufactured domestically. In the absence of energy conservation standards, DOE estimates that there would be 104 domestic production workers in the circulator pump industry in 2026, the year of compliance.

DOE's analysis forecasts that the industry will domestically employ 171 production and non-production workers in the circulator pump industry in 2026 in the absence of energy conservation standards. Table V.7 presents the range of potential impacts of energy conservation standards on U.S. production workers of circulator pumps.

TABLE V.7—POTENTIAL CHANGES IN THE TOTAL NUMBER OF CIRCULATOR PUMP PRODUCTION WORKERS IN DIRECT EMPLOYMENT IN 2026

	No-new-standards case	Trial standard level			
		1	2	3	4
Number of Domestic Production Workers	104	104	75–149	84–167	92–183
Number of Domestic Non-Production Workers	67	67	96	107	118
Total Domestic Direct Employment **	171	171	171–245	191–274	210–301
Potential Changes in Direct Employment		0	0–74	20–103	39–130

* Numbers in parentheses indicate negative numbers.
** This field presents impacts on domestic direct employment, which aggregates production and non-production workers.

In manufacturer interviews, several manufacturers that produce high-efficiency circulator pumps would require additional engineers to redesign circulator pumps and production processes. Additionally, higher efficiency pump manufacturing is more labor intensive, and would require additional labor expenditures. DOE understands circulator pumps with ECMs are primarily manufactured outside the U.S. However, during manufacturer interviews, manufacturers indicated that they would likely expand their ECM production capacities in the U.S. in the presence of a standard at TSL 2 or higher. Therefore, DOE modeled a low-end employment range that assumes half of domestic production would be relocated to foreign countries due to the energy conservation standard. The high-end of the range represents no change in the percentage of models manufactured in the U.S.

Due different variations in manufacturing labor practices, actual direct employment could vary depending on manufacturers' preference for high capital or high labor practices in response to standards. DOE notes that the employment impacts discussed here are independent of the indirect employment impacts to the broader U.S. economy, which are documented in chapter 15 of the accompanying TSD.

DOE requests comment on its estimates of domestic employment for circulator pump manufacturing in the presence of an energy conservation standards.

c. Impacts on Manufacturing Capacity

During manufacturer interviews, industry feedback indicated that manufacturers' current production capacity was strained due to upstream supply chain constraints. Additionally, manufacturers expressed that additional production lines would be required during the conversion period if standards were set at a level requiring ECMs. However, many manufacturers noted that their portfolios have expanded in recent years to accommodate more circulator pumps using ECMs. Furthermore, manufacturers indicated that a circulator pump utilizing an ECM could support a wider range of applications compared to a circulator pump utilizing an induction motor.

d. Impacts on Subgroups of Manufacturers

As discussed in section IV.J.2 of this document, using average cost assumptions to develop an industry cash-flow estimate may not be adequate for assessing differential impacts among manufacturer subgroups. Small manufacturers, niche manufacturers, and manufacturers exhibiting a cost structure substantially different from the industry average could be affected disproportionately. DOE used the results of the industry characterization to group manufacturers exhibiting similar characteristics. Consequently, DOE identified small business manufacturers as a subgroup for a separate impact analysis.

For the small business subgroup analysis, DOE applied the small business size standards published by the Small Business Administration (''SBA'') to determine whether a company is considered a small business. The size standards are codified at 13 CFR part 201. To be categorized as a small business under NAICS code 333914, ''Measuring, Dispensing, and Other Pumping Equipment Manufacturing'' a circulator pump manufacturer and its affiliates may employ a maximum of 750 employees. The 750-employee threshold includes all employees in a business's parent company and any other subsidiaries. Based on this classification, DOE identified three potential manufacturers that could qualify as domestic small businesses.

The small business subgroup analysis is discussed in more detail in chapter 12 of the NOPR TSD. DOE examines the potential impacts on small business manufacturers in section VI.B of this NOPR.

e. Cumulative Regulatory Burden

One aspect of assessing manufacturer burden involves looking at the cumulative impact of multiple DOE standards and the product-specific regulatory actions of other Federal agencies that affect the manufacturers of a covered product or equipment. While any one regulation may not impose a significant burden on manufacturers, the combined effects of several existing or impending regulations may have serious consequences for some manufacturers, groups of manufacturers, or an entire industry. Assessing the impact of a single regulation may overlook this cumulative regulatory burden. In addition to energy conservation standards, other regulations can significantly affect manufacturers' financial operations. Multiple regulations affecting the same manufacturer can strain profits and lead companies to abandon product lines or markets with lower expected future returns than competing products. For these reasons, DOE conducts an analysis of cumulative regulatory burden as part of its rulemakings pertaining to appliance efficiency. DOE requests information regarding the impact of cumulative regulatory burden on manufacturers of circulator pumps associated with multiple DOE standards or product-specific regulatory actions of other Federal agencies.

DOE evaluates equipment-specific regulations that will take effect approximately 3 years before or after the 2026 compliance date of any energy conservation standards for circulator pumps. DOE is aware that circulator pump manufacturers produce other equipment or products that circulator pump manufacturers produce including dedicated-purpose pool pumps [74] and commercial and industrial pumps.[75] None of these products or equipment have proposed or adopted energy conservation standards that require compliance within 3 years of the proposed energy conservation standards for circulator pumps in this NOPR. If DOE proposes or finalizes any energy conservation standards for these products or equipment prior to finalizing energy conservation standards for circulator pumps, DOE will include the energy conservation standards for these products or equipment as part of the cumulative regulator burden for this circulator pump rulemaking.

3. National Impact Analysis

This section presents DOE's estimates of the national energy savings and the NPV of consumer benefits that would result from each of the TSLs considered as potential standards.

a. Significance of Energy Savings

To estimate the energy savings attributable to potential standards for circulator pumps, DOE compared their energy consumption under the no-new-standards case to their anticipated energy consumption under each TSL. The savings are measured over the entire lifetime of products purchased in the 30-year period that begins in the year of anticipated compliance with amended standards (2026–2055). Table V.8 presents DOE's projections of the national energy savings for each TSL considered for circulator pumps. The savings were calculated using the approach described in section IV.H of this document.

TABLE V.8—CUMULATIVE NATIONAL ENERGY SAVINGS FOR CIRCULATOR PUMPS; 30 YEARS OF SHIPMENTS

[2026–2055]

	Trial standard level			
	1	2	3	4
	quads			
Primary energy	0.07	0.43	0.78	0.92
FFC energy	0.07	0.45	0.81	0.96

OMB Circular A–4 [76] requires agencies to present analytical results, including separate schedules of the monetized benefits and costs that show the type and timing of benefits and costs. Circular A–4 also directs agencies to consider the variability of key elements underlying the estimates of benefits and costs. For this rulemaking, DOE undertook a sensitivity analysis using 9 years, rather than 30 years, of product shipments. The choice of a 9-year period is a proxy for the timeline in EPCA for the review of certain energy conservation standards and potential revision of and compliance with such revised standards.[77] The review timeframe established in EPCA is generally not synchronized with the product lifetime, product manufacturing cycles, or other factors specific to circulator pumps. Thus, such results are presented for informational purposes only and are not indicative of any change in DOE's analytical methodology. The NES sensitivity analysis results based on a 9-year analytical period are presented in Table V.9. The impacts are counted over the lifetime of circulator pumps purchased in 2026–2034.

TABLE V.9—CUMULATIVE NATIONAL ENERGY SAVINGS FOR CIRCULATOR PUMPS; 9 YEARS OF SHIPMENTS

[2026–2034]

	Trial standard level			
	1	2	3	4
	quads			
Primary energy	0.03	0.15	0.26	0.30
FFC energy	0.03	0.16	0.27	0.31

[74] *www.regulations.gov/docket/EERE-2022-BT-STD-0001.*

[75] *www.regulations.gov/docket/EERE-2021-BT-STD-0018.*

[76] U.S. Office of Management and Budget. *Circular A–4: Regulatory Analysis.* September 17, 2003. *https://www.whitehouse.gov/wp-content/uploads/legacy_drupal_files/omb/circulars/A4/a-4.pdf* (last accessed July 3, 2022).

[77] Section 325(m) of EPCA requires DOE to review its standards at least once every 6 years, and requires, for certain products, a 3-year period after any new standard is promulgated before compliance is required, except that in no case may any new standards be required within 6 years of the compliance date of the previous standards. While adding a 6-year review to the 3-year compliance period adds up to 9 years, DOE notes that it may undertake reviews at any time within the 6-year period and that the 3-year compliance date may yield to the 6-year backstop. A 9-year analysis period may not be appropriate given the variability that occurs in the timing of standards reviews and the fact that for some products, the compliance period is 5 years rather than 3 years.

b. Net Present Value of Consumer Costs and Benefits

DOE estimated the cumulative NPV of the total costs and savings for consumers that would result from the TSLs considered for circulator pumps. In accordance with OMB's guidelines on regulatory analysis,[78] DOE calculated NPV using both a 7-percent and a 3-percent real discount rate. Table V.10 shows the consumer NPV results with impacts counted over the lifetime of products purchased in 2026–2055.

TABLE V.10—CUMULATIVE NET PRESENT VALUE OF CONSUMER BENEFITS FOR CIRCULATOR PUMPS; 30 YEARS OF SHIPMENTS

[2026–2055]

Discount rate	Trial standard level			
	1	2	3	4
	million $2021			
3 percent	575.1	1,770.7	1,994.1	2,069.3
7 percent	293.9	731.6	626.6	579.5

The NPV results based on the aforementioned 9-year analytical period are presented in Table V.11. The impacts are counted over the lifetime of products purchased in 2026–2055. As mentioned previously, such results are presented for informational purposes only and are not indicative of any change in DOE's analytical methodology or decision criteria.

TABLE V.11—CUMULATIVE NET PRESENT VALUE OF CONSUMER BENEFITS FOR CIRCULATOR PUMPS; 9 YEARS OF SHIPMENTS

[2026–2034]

Discount rate	Trial standard level			
	1	2	3	4
	million $2021			
3 percent	285.2	813.4	917.2	951.6
7 percent	180.1	429.0	377.7	355.1

The previous results reflect the assumption of a constant price for circulator pumps over the analysis period (see section IV.H.3 of this document). As part of the NIA, DOE also conducted a sensitivity analysis that considered two scenarios that use inputs from variants of the AEO 2022 Reference case: The AEO 2022 High Economic Growth scenario, which has a higher energy price trend relative to the reference case, and the AEO 2022 Low Economic Growth scenario, which has a lower energy price trend relative to the reference case, as well as a higher price learning rate. The higher learning rate in this scenario accelerates the adoption of more efficient circulator pump options in the no-new-standards case (relative to the reference scenario) decreasing the available energy savings attributable to a standard. The results of these alternative cases are presented in appendix 10C of the NOPR TSD.

c. Indirect Impacts on Employment

It is estimated that that energy conservation standards for circulator pumps would reduce energy expenditures for consumers of those products, with the resulting net savings being redirected to other forms of economic activity. These expected shifts in spending and economic activity could affect the demand for labor. As described in section IV.N of this document, DOE used an input/output model of the U.S. economy to estimate indirect employment impacts of the TSLs that DOE considered. There are uncertainties involved in projecting employment impacts, especially changes in the later years of the analysis. Therefore, DOE generated results for near-term timeframes (2026–2031), where these uncertainties are reduced.

The results suggest that the proposed standards would be likely to have a negligible impact on the net demand for labor in the economy. The net change in jobs is so small that it would be imperceptible in national labor statistics and might be offset by other, unanticipated effects on employment. Chapter 16 of the NOPR TSD presents detailed results regarding anticipated indirect employment impacts.

4. Impact on Utility or Performance of Products

As discussed in section III.F.1.d of this document, DOE has tentatively concluded that the standards proposed in this NOPR would not lessen the utility or performance of circulator pumps under consideration in this rulemaking. Manufacturers of these products currently offer units that meet or exceed the proposed standards.

5. Impact of Any Lessening of Competition

DOE considered any lessening of competition that would be likely to result from new or amended standards. As discussed in section III.F.1.e, the Attorney General determines the impact, if any, of any lessening of competition likely to result from a proposed standard, and transmits such determination in writing to the Secretary, together with an analysis of the nature and extent of such impact. To

[78] U.S. Office of Management and Budget. *Circular A–4: Regulatory Analysis.* September 17, 2003. *https://www.whitehouse.gov/wp-content/uploads/legacy_drupal_files/omb/circulars/A4/a-4.pdf* (last accessed July 3, 2022).

assist the Attorney General in making this determination, DOE has provided DOJ with copies of this NOPR and the accompanying TSD for review. DOE will consider DOJ's comments on the proposed rule in determining whether to proceed to a final rule. DOE will publish and respond to DOJ's comments in that document. DOE invites comment from the public regarding the competitive impacts that are likely to result from this proposed rule. In addition, stakeholders may also provide comments separately to DOJ regarding these potential impacts. See the **ADDRESSES** section for information to send comments to DOJ.

6. Need of the Nation To Conserve Energy

Enhanced energy efficiency, where economically justified, improves the Nation's energy security, strengthens the economy, and reduces the environmental impacts (costs) of energy production. Reduced electricity demand due to energy conservation standards is also likely to reduce the cost of maintaining the reliability of the electricity system, particularly during peak-load periods. Chapter 15 in the NOPR TSD presents the estimated impacts on electricity generating capacity, relative to the no-new-standards case, for the TSLs that DOE considered in this rulemaking.

Energy conservation resulting from potential energy conservation standards for circulator pumps is expected to yield environmental benefits in the form of reduced emissions of certain air pollutants and greenhouse gases. Table V.12 provides DOE's estimate of cumulative emissions reductions expected to result from the TSLs considered in this rulemaking. The emissions were calculated using the multipliers discussed in section IV.K. DOE reports annual emissions reductions for each TSL in chapter 13 of the NOPR TSD.

TABLE V.12—CUMULATIVE EMISSIONS REDUCTION FOR CIRCULATOR PUMPS SHIPPED IN 2026–2055

	Trial standard level			
	1	2	3	4
Power Sector Emissions:				
CO_2 (million metric tons)	2.35	14.69	26.50	31.26
CH_4 (thousand tons)	0.20	1.22	2.20	2.60
N_2O (thousand tons)	0.03	0.17	0.31	0.37
SO_2 (thousand tons)	1.24	7.68	13.83	16.31
NO_X (thousand tons)	1.23	7.67	13.82	16.30
Hg (tons)	0.01	0.05	0.09	0.10
Upstream Emissions:				
CO_2 (million metric tons)	0.17	1.07	1.93	2.28
CH_4 (thousand tons)	15.98	100.77	182.23	215.12
N_2O (thousand tons)	0.00	0.01	0.01	0.01
SO_2 (thousand tons)	2.56	16.16	29.22	34.49
NO_X (thousand tons)	0.01	0.08	0.14	0.16
Hg (tons)	0.00	0.00	0.00	0.00
Total FFC Emissions:				
CO_2 (million metric tons)	2.52	15.76	28.43	33.54
CH_4 (thousand tons)	16.18	101.99	184.44	217.72
N_2O (thousand tons)	0.03	0.18	0.32	0.38
SO_2 (thousand tons)	3.80	23.84	43.05	50.79
NO_X (thousand tons)	1.25	7.75	13.96	16.47
Hg (tons)	0.01	0.05	0.09	0.10

As part of the analysis for this rulemaking, DOE estimated monetary benefits likely to result from the reduced emissions of CO_2 that DOE estimated for each of the considered TSLs for circulator pumps. Section IV.L of this document discusses the SC-CO_2 values that DOE used. Table V.13 presents the value of CO_2 emissions reduction at each TSL for each of the SC-CO_2 cases. The time-series of annual values is presented for the proposed TSL in chapter 14 of the NOPR TSD.

TABLE V.13—PRESENT VALUE OF CO_2 EMISSIONS REDUCTION FOR CIRCULATOR PUMPS SHIPPED IN 2026–2055

TSL	SC-CO_2 case			
	Discount rate and statistics			
	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile
	million $2021			
1	26.1	108.0	167.2	328.9
2	157.6	661.3	1,027.3	2,012.1
3	282.0	1,187.1	1,845.8	3,611.3
4	331.7	1,397.7	2,173.9	4,251.6

As discussed in section IV.L.2, DOE estimated the climate benefits likely to result from the reduced emissions of methane and N_2O that DOE estimated for each of the considered TSLs for circulator pumps. Table V.14 presents the value of the CH_4 emissions reduction at each TSL, and Table V.15 presents the value of the N_2O emissions reduction at each TSL. The time-series of annual values is presented for the proposed TSL in chapter 14 of the NOPR TSD.

TABLE V.14—PRESENT VALUE OF METHANE EMISSIONS REDUCTION FOR CIRCULATOR PUMPS SHIPPED IN 2026–2055

TSL	SC-CH_4 case			
	Discount rate and statistics			
	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile
	million $2021			
1	7.5	21.4	29.6	56.9
2	46.1	133.1	184.6	353.1
3	82.6	239.9	333.0	636.1
4	97.3	282.9	392.7	749.8

TABLE V.15—PRESENT VALUE OF NITROUS OXIDE EMISSIONS REDUCTION FOR CIRCULATOR PUMPS SHIPPED IN 2026–2055

TSL	SC-N_2O Case			
	Discount rate and statistics			
	5%	3%	2.5%	3%
	Average	Average	Average	95th percentile
	million $2021			
1	0.1	0.4	0.7	1.1
2	0.7	2.6	4.0	6.9
3	1.2	4.7	7.2	12.5
4	1.4	5.5	8.5	14.7

DOE is well aware that scientific and economic knowledge about the contribution of CO_2 and other GHG emissions to changes in the future global climate and the potential resulting damages to the global and U.S. economy continues to evolve rapidly. DOE, together with other Federal agencies, will continue to review methodologies for estimating the monetary value of reductions in CO_2 and other GHG emissions. This ongoing review will consider the comments on this subject that are part of the public record for this and other rulemakings, as well as other methodological assumptions and issues. DOE notes that the proposed standards would be economically justified even without inclusion of monetized benefits of reduced GHG emissions.

DOE also estimated the monetary value of the health benefits associated with NO_X and SO_2 emissions reductions anticipated to result from the considered TSLs for circulator pumps. The dollar-per-ton values that DOE used are discussed in section IV.L of this document. Table V.16 presents the present value for NO_X emissions reduction for each TSL calculated using 7-percent and 3-percent discount rates, and Table V.17 presents similar results for SO_2 emissions reductions. The results in these tables reflect application of EPA's low dollar-per-ton values, which DOE used to be conservative. The time-series of annual values is presented for the proposed TSL in chapter 14 of the NOPR TSD.

TABLE V.16–PRESENT VALUE OF NO_X EMISSIONS REDUCTION FOR CIRCULATOR PUMPS SHIPPED IN 2026–2055

TSL	3% Discount rate	7% Discount rate
	million $2021	
1	165.4	75.9
2	1,006.0	444.3
3	1,802.9	788.4
4	2,121.4	924.2

TABLE V.17—PRESENT VALUE OF SO_2 EMISSIONS REDUCTION FOR CIRCULATOR PUMPS SHIPPED IN 2026–2055

TSL	3% Discount rate	7% Discount rate
	million $2021	
1	73.5	34.9
2	444.2	202.7
3	795.0	359.1
4	935.0	420.8

7. Other Factors

The Secretary of Energy, in determining whether a standard is economically justified, may consider any other factors that the Secretary deems to be relevant. (42 U.S.C. 6295(o)(2)(B)(i)(VII)) No other factors were considered in this analysis.

8. Summary of Economic Impacts

Table V.18 presents the NPV values that result from adding the estimates of the potential economic benefits resulting from reduced GHG and NO_X and SO_2 emissions to the NPV of consumer benefits calculated for each TSL considered in this rulemaking. The consumer benefits are domestic U.S. monetary savings that occur as a result of purchasing the covered circulator pumps, and are measured for the lifetime of products shipped in 2026–2055. The benefits associated with reduced GHG emissions resulting from the adopted standards are global benefits, and are also calculated based on the lifetime of circulator pumps shipped in 2026–2055.

TABLE V.18—CONSUMER NPV COMBINED WITH PRESENT VALUE OF BENEFITS FROM CLIMATE AND HEALTH BENEFITS

Category	TSL 1	TSL 2	TSL 3	TSL 4
3% discount rate for NPV of Consumer and Health Benefits (billion 2021$)				
5% Average SC-GHG case	0.8	3.4	5.0	5.6
3% Average SC-GHG case	0.9	4.0	6.0	6.8
2.5% Average SC-GHG case	1.0	4.4	6.8	7.7
3% 95th percentile SC-GHG case	1.2	5.6	8.9	10.1
7% discount rate for NPV of Consumer and Health Benefits (billion 2021$)				
5% Average SC-GHG case	0.4	1.6	2.1	2.4
3% Average SC-GHG case	0.5	2.2	3.2	3.6
2.5% Average SC-GHG case	0.6	2.6	4.0	4.5
3% 95th percentile SC-GHG case	0.8	3.8	6.0	6.9

C. Conclusion

When considering new or amended energy conservation standards, the standards that DOE adopts for any type (or class) of covered equipment must be designed to achieve the maximum improvement in energy efficiency that the Secretary determines is technologically feasible and economically justified. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(A)) In determining whether a standard is economically justified, the Secretary must determine whether the benefits of the standard exceed its burdens by, to the greatest extent practicable, considering the seven statutory factors discussed previously. (42 U.S.C. 6316(a); 42 U.S.C. 6295(o)(2)(B)(i)) The new or amended standard must also result in significant conservation of energy. (42 U.S.C. 6295(o)(3)(B))

For this NOPR, DOE considered the impacts of standards for circulator pumps at each TSL, beginning with the maximum technologically feasible level, to determine whether that level was economically justified. Where the max-tech level was not justified, DOE then considered the next most efficient level and undertook the same evaluation until it reached the highest efficiency level that is both technologically feasible and economically justified and saves a significant amount of energy.

To aid the reader as DOE discusses the benefits and/or burdens of each TSL, tables in this section present a summary of the results of DOE's quantitative analysis for each TSL. In addition to the quantitative results presented in the tables, DOE also considers other burdens and benefits that affect economic justification. These include the impacts on identifiable subgroups of consumers who may be disproportionately affected by a national standard and impacts on employment.

1. Benefits and Burdens of TSLs Considered for Circulator Pumps Standards

Table V.19 and Table V.20 summarize the quantitative impacts estimated for each TSL for circulator pumps. The national impacts are measured over the lifetime of circulator pumps purchased in the 30-year period that begins in the anticipated year of compliance with standards (2026–2055). The energy savings, emissions reductions, and value of emissions reductions refer to full-fuel-cycle results. The efficiency levels contained in each TSL are described in section V.A of this document.

TABLE V.19—SUMMARY OF ANALYTICAL RESULTS FOR CIRCULATOR PUMP TSLS: NATIONAL IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4
Cumulative FFC National Energy Savings:				

TABLE V.19—SUMMARY OF ANALYTICAL RESULTS FOR CIRCULATOR PUMP TSLS: NATIONAL IMPACTS—Continued

Category	TSL 1	TSL 2	TSL 3	TSL 4
Quads	0.07	0.45	0.81	0.96
Cumulative FFC Emissions Reduction:				
CO_2 (*million metric tons*)	2.5	15.8	28.4	33.5
CH_4 (*thousand tons*)	16.2	102.0	184.4	217.7
N_2O (*thousand tons*)	0.03	0.18	0.32	0.38
SO_2 (*thousand tons*)	3.8	23.8	43.1	50.8
NO_X (*thousand tons*)	1.2	7.7	14.0	16.5
Hg (*tons*)	0.01	0.05	0.09	0.10
Present Value of Benefits and Costs (3% discount rate, billion 2021$):				
Consumer Operating Cost Savings	0.58	3.41	6.03	7.05
Climate Benefits *	0.13	0.80	1.43	1.69
Health Benefits **	0.24	1.45	2.60	3.06
Total Benefits †	0.94	5.65	10.06	11.79
Consumer Incremental Product Costs ‡	0.00	1.64	4.03	4.98
Consumer Net Benefits	0.58	1.77	1.99	2.07
Total Net Benefits	0.94	4.02	6.02	6.81
Present Value of Benefits and Costs (7% discount rate, billion 2021$):				
Consumer Operating Cost Savings	0.29	1.68	2.94	3.43
Climate Benefits *	0.13	0.80	1.43	1.69
Health Benefits **	0.11	0.65	1.15	1.34
Total Benefits †	0.53	3.12	5.52	6.46
Consumer Incremental Product Costs ‡	0.00	0.95	2.32	2.85
Consumer Net Benefits	0.29	0.73	0.63	0.58
Total Net Benefits	0.53	2.18	3.21	3.61

Note: This table presents the costs and benefits associated with circulator pumps shipped in 2026–2055. These results include benefits to consumers which accrue after 2055 from the products shipped in 2026–2055.

* Climate benefits are calculated using four different estimates of the global SC-GHG (see section IV.L of this notice). For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3 percent discount rate are shown, but the Department does not have a single central SC-GHG point estimate, and it emphasizes the importance and value of considering the benefits calculated using all four SC-GHG estimates.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for NO_X and SO_2) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. The health benefits are presented at real discount rates of 3 and 7 percent. See section IV.L of this document for more details.

† Total and net benefits include consumer, climate, and health benefits. For presentation purposes, total and net benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with 3-percent discount rate, but the Department does not have a single central SC-GHG point estimate. DOE emphasizes the importance and value of considering the benefits calculated using all four SC-GHG estimates. See Table V.18 for net benefits using all four SC-GHG estimates. On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087) granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and present monetized benefits where appropriate and permissible under law.

‡ Costs include incremental equipment costs as well as installation costs.

TABLE V.20—SUMMARY OF ANALYTICAL RESULTS FOR CIRCULATOR PUMP TSLS: MANUFACTURER AND CONSUMER IMPACTS

Category	TSL 1	TSL 2	TSL 3	TSL 4
Manufacturer Impacts:				
Industry NPV (*million* 2021$) (No-new-standards case INPV = 325.9)	322.6	261.6–347.3	228.9–351.4	219.91–376.7
Industry NPV (*% change*)	(3.2)	(19.7)–6.6	(29.8)–7.8	(32.5)–15.6
Consumer Average LCC Savings (2021$):				
All Circulators	125.2	103.2	105.3	97.6
Consumer Simple PBP (years):				
All Circulators	0.0	4.2	5.4	5.6
Percent of Consumers that Experience a Net Cost:				
All Circulators	0.0	29.2	46.4	49.7

Parentheses indicate negative (−) values.

DOE first considered TSL 4, which represents the max-tech efficiency level, and would require differential temperature-based control schemes to be implemented in the field to deliver savings. TSL 4 would save an estimated 0.96 quads of energy, an amount DOE considers significant. Under TSL 4, the NPV of consumer benefit would be

$0.58 billion using a discount rate of 7 percent, and $2.07 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 4 are 33.5 Mt of CO_2, 50.8 thousand tons of SO_2, 16.5 thousand tons of NO_X, 0.10 tons of Hg, 217.7 thousand tons of CH_4, and 0.38 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC–GHG at a 3-percent discount rate) at TSL 4 is $1.69 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 4 is $1.34 billion using a 7-percent discount rate and $3.06 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 4 is $3.61 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 4 is $6.81 billion. DOE notes that it provides the estimated total NPV as additional information, but primarily relies upon the NPV of consumer benefits in its analysis for determining whether a proposed standard level is economically justified.

At TSL 4, the average LCC impact is a savings of $97.6. The simple payback period is 5.6 years. The fraction of consumers experiencing a net LCC cost approximately 50 percent of consumers.

At TSL 4, the projected change in INPV ranges from a decrease of $106.0 million to an increase of $50.8 million, which corresponds to decrease of 32.5 percent and an increase of 15.6 percent, respectively. DOE estimates that industry must invest $111.8 million to comply with standards set at TSL 4. This investment is primarily driven by converting all existing products to include differential-temperature based controls and the associate product conversion costs that would be needed to support such a transition. DOE estimates that only two percent of circulator pump shipments would meet the efficiency levels analyzed at TSL 4.

DOE also notes that the estimated energy and economic savings from TSL 4 are highly dependent on the end-use systems in which the circulator pumps are installed (*e.g.,* hydronic heating or water heating applications). Circulator pumps are typically added to systems when installed in the field and can be replaced separately than the end-use appliance in which they are paired. Depending on the type of controls that the end-use appliance contains, the circulator pumps may not see the field savings benefits from the technologies incorporated in TSL 4 because the end-use system cannot accommodate full variable-speed operation. In particular, some systems will not achieve any additional savings from differential temperature controls as compared to a single speed ECM with no controls (*i.e.,* TSL 2). While the analysis includes the best available assumptions on the distribution of system curves and single-zone versus multi-zone applications, variation in those assumptions could have a large impact on savings potential and resulting economics providing uncertainty in the savings associated with TSL 4.

The Secretary tentatively concludes that at TSL 4 for circulator pump, the benefits of energy savings, positive NPV of consumer benefits, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the economic burden on many consumers, and the impacts on manufacturers, including the large conversion costs, profit margin impacts that could result in a large reduction in INPV, and the lack of manufacturers currently offering products meeting the efficiency levels required at this TSL, including small businesses. Almost a majority of circulator pump customers (49.7 percent) would experience a net cost and manufacturers would have to significantly ramp up production of more efficient models since only 2 percent of shipments currently meet TSL efficiency levels. In addition, the Secretary is also tentatively concerned about the uncertainty regarding the potential energy savings as compared to the field savings due to the lack of end-use appliances not being able to respond to differential temperature controls from the circulator pump. Consequently, the Secretary has tentatively concluded that TSL 4 is not economically justified.

DOE then considered TSL 3, which represents efficiency level three, and would require automatic proportional pressure controls to be added to the circulator pump. Automatic proportional pressure controls are used to simulate variable flow aiding in energy use reductions from the pump. TSL 3 would save an estimated 0.81 quads of energy, an amount DOE considers significant. Under TSL 3, the NPV of consumer benefit would be $0.63 billion using a discount rate of 7 percent, and $1.99 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 3 are 28.4 Mt of CO_2, 43.1 thousand tons of SO_2, 14.0 thousand tons of NO_X, 0.09 tons of Hg, 184.4 thousand tons of CH_4, and 0.32 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC-GHG at a 3-percent discount rate) at TSL 3 is $1.43 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 3 is $1.15 billion using a 7-percent discount rate and $2.60 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 3 is $3.21 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 4 is $6.02 billion. DOE notes that it provides the estimated total NPV as additional information, but primarily relies upon the NPV of consumer benefits in its analysis determining whether a proposed standard level is economically justified.

At TSL 3, the average LCC impact is a savings of $105.3. The simple payback period is 5.4 years. The fraction of consumers experiencing a net LCC cost is 46.4 percent.

At TSL 3, the projected change in INPV ranges from a decrease of $97.0 million to an increase of $25.5 million, which corresponds to a decrease of 29.8 percent and an increase of 7.8 percent, respectively. DOE estimates that industry must invest $111.1 million to comply with standards set at TSL 3. DOE estimates that approximately 12 percent of circulator pump shipments would meet the efficiency levels analyzed at TSL 3.

Similar to TSL 4, DOE also notes that the estimated energy and economic savings from TSL 3 are highly dependent on the systems in which the circulator pumps are installed. Depending on the type of controls that the end-use appliance contains, the circulator pumps may not see the field savings benefits from the technologies incorporated in TSL 3 because the end-use system cannot accommodate full variable-speed operation from the automatic proportional pressure controls. In particular, some systems will not achieve any additional savings from proportional pressure controls as compared to a single speed ECM with no controls (*i.e.,* TSL 2). While the analysis includes the best available assumptions on the distribution of system curves and single-zone versus multi-zone applications, variation in those assumptions could have a large impact on savings potential and resulting economics providing uncertainty in the benefits for TSL 3.

The Secretary tentatively concludes that at TSL 3 for circulator pump, the benefits of energy savings, positive NPV of consumer benefits, emission reductions, and the estimated monetary value of the emissions reductions would be outweighed by the economic burden on many consumers, and the impacts on manufacturers, including the large conversion costs, profit margin impacts that could result in a large reduction in INPV, and the lack of manufacturers currently offering products meeting the efficiency levels required at this TSL, including small businesses. Almost a majority of circulator pump customers (46.4 percent) would experience a net cost. While most manufacturers offer a product that would meet TSL 3 efficiencies and include automatic pressure- or temperature-based controls, these are manufactured at low production volume. All manufacturers would still need to incur significant product conversion expenses and make capital investments to extend both automatic pressure- and temperature-based controls to all circulator pumps distributed in commerce. In addition, the Secretary is also tentatively concerned about the uncertainty regarding the potential energy savings as compared to the field savings due to the lack of end-use appliances not being able to respond to automatic proportional pressure control from the circulator pump. Consequently, the Secretary has tentatively concluded that TSL 3 is not economically justified.

DOE then considered TSL 2, which represents efficiency level two and includes single speed ECMs in the circulator pump. Single-speed ECMs do not depend on the controls of the end-use appliance in order to realize the energy-savings benefits of the variable speed motor. In addition, TSL 2 is the proposed standard level recommended by the CPWG. TSL 2 would save an estimated 0.45 quads of energy, an amount DOE considers significant. Under TSL 2, the NPV of consumer benefit would be $0.73 billion using a discount rate of 7 percent, and $1.77 billion using a discount rate of 3 percent.

The cumulative emissions reductions at TSL 2 are 15.8 Mt of CO_2, 23.8 thousand tons of SO_2, 7.7 thousand tons of NO_X, 0.05 tons of Hg, 102.0 thousand tons of CH_4, and 0.18 thousand tons of N_2O. The estimated monetary value of the climate benefits from reduced GHG emissions (associated with the average SC-GHG at a 3-percent discount rate) at TSL 2 is $0.80 billion. The estimated monetary value of the health benefits from reduced SO_2 and NO_X emissions at TSL 2 is $0.65 billion using a 7-percent discount rate and $1.45 billion using a 3-percent discount rate.

Using a 7-percent discount rate for consumer benefits and costs, health benefits from reduced SO_2 and NO_X emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated total NPV at TSL 2 is $2.18 billion. Using a 3-percent discount rate for all benefits and costs, the estimated total NPV at TSL 3 is $4.02 billion. DOE notes that it provides the estimated total NPV as additional information, but primarily relies upon the NPV of consumer benefits in its analysis for determining whether a proposed standard level is economically justified.

At TSL 2, the average LCC impact is a savings of $103.2. The simple payback period is 4.2 years. The fraction of consumers experiencing a net LCC cost is 29.2 percent.

At TSL 2, the projected change in INPV ranges from a decrease of $64.3 million to an increase of $21.4 million, which corresponds to decrease of 19.7 percent and an increase of 6.6 percent, respectively. DOE estimates that industry must invest $77.0 million to comply with standards set at TSL 2. DOE estimates that approximately 19 percent of circulator pump shipments would meet the efficiency levels analyzed at TSL 2. At TSL 2, most manufacturers have current circulator pump offerings at this level.

A standard set at TSL 2 essentially guarantees energy savings in all applications currently served by an induction motor, as the savings accrue from motor efficiency alone rather than from a particular control strategy that must be properly matched to the system in the field. In comparison, TSL 3 and 4 include an ECM motor like in TSL 2, but TSL 3 and 4 also include the associated variable speed controls that must be properly matched in the field. TSL 2 also allows and encourages uptake of circulators with controls, as manufacturers may choose to prioritize variable speed ECM as opposed to single speed ECM. This could increase the potential savings from TSL 2 from those captured in the analysis, while providing consumers and manufacturers with flexibility to select the motor and/or control strategy most appropriate to their given application.

After considering the analysis and weighing the benefits and burdens, the Secretary has tentatively concluded that a standard set at TSL 2 for circulator pumps would be economically justified. At this TSL, the average LCC is positive. An estimated 29.2 percent, less than a third, of circulator pump consumers experience a net cost. The FFC national energy savings are significant and the NPV of consumer benefits is positive using both a 3-percent and 7-percent discount rate. Manufacturers supported the CPWG recommendation of establishing standards set at TSL 2. Therefore, DOE anticipates that manufacturers will be able to absorb the capital and product conversion costs to manufacture more efficient equipment. Notably, the benefits to consumers significantly outweigh the cost to manufacturers.

In addition, TSL 2 is consistent with the recommendations voted on by the CPWG and approved by the ASRAC. (*See* Docket No. EERE–2016–BT–STD–0004, No. 98) DOE has encouraged the negotiation of new standard levels as a means for interested parties, representing diverse points of view, to analyze and recommend energy conservation standards to DOE. Such negotiations may often expedite the rulemaking process. In addition, standard levels recommended through a negotiation may increase the likelihood for regulatory compliance, while decreasing the risk of litigation.

As stated, DOE conducts the walk-down analysis to determine the TSL that represents the maximum improvement in energy efficiency that is technologically feasible and economically justified as required under EPCA. The walk-down is not a comparative analysis, as a comparative analysis would result in the maximization of net benefits instead of energy savings that are technologically feasible and economically justified, which would be contrary to the statute. 86 FR 70892, 70908. Although DOE has not conducted a comparative analysis to select the proposed energy conservation standards, DOE notes that despite the average consumer LCC savings being similar between TSL 2 ($103.2), TSL 3 ($105.3) and TSL 4 ($97.6), TSL 2 has a much lower fraction of consumers who experience a net cost (29.2%) than TSL 3 (46.4%) and TSL 4 (49.7%). In terms of industry investment to comply with each standard level, TSL 2 ($77.0 million) has considerably lower impact than TSL 3 ($111.1 million) and TSL 4 ($111.8 million). Finally, when comparing the cumulative NPV of consumer benefit using a 7% discount rate, TSL 2 ($0.73 billion) has a higher benefit value than both TSL 3 ($0.63 billion) and TSL 4 ($0.58 billion), while for a 3% discount rate, TSL 2 ($1.77 billion) is below TSL 3 ($1.99 billion) and TSL 4 (2.07 billion).

Therefore, based on the previous considerations, DOE proposes to adopt the energy conservation standards for circulator pumps at TSL 2. The proposed energy conservation standards for circulator pumps, which are expressed as CEI, are shown in Table V.21. As stated in section III.A.1, this proposed standard level of a maximum CEI of 1.00, or TSL 2, is equivalent to the standard level recommended by the CPWG in the November 2016 CWPG Recommendations, in which was described both as EL 2 and as a CEI value of 1.00.

TABLE V.21—PROPOSED ENERGY CONSERVATION STANDARDS FOR CIRCULATOR PUMPS

Equipment class	Maximum CEI
(All Circulator Pumps)	1.00

2. Annualized Benefits and Costs of the Proposed Standards

The benefits and costs of the proposed standards can also be expressed in terms of annualized values. The annualized net benefit is (1) the annualized national economic value (expressed in 2021$) of the benefits from operating products that meet the proposed standards (consisting primarily of operating cost savings from using less energy, minus increases in product purchase costs, and (2) the annualized monetary value of the climate and health benefits from emission reductions.

Table V.22 shows the annualized values for circulator pumps under TSL 2, expressed in 2021$. The results under the primary estimate are as follows.

Using a 7-percent discount rate for consumer benefits and costs and health benefits from reduced NO_X and SO_2 emissions, and the 3-percent discount rate case for climate benefits from reduced GHG emissions, the estimated cost of the standards proposed in this rule is $93.5 million per year in increased equipment costs, while the estimated annual benefits are $165.8 in reduced equipment operating costs, $44.4 million in climate benefits, and $63.9 million in health benefits. In this case, the net benefit would amount to $180.5 million per year.

Using a 3-percent discount rate for all benefits and costs, the estimated cost of the proposed standards is $91.2 million per year in increased equipment costs, while the estimated annual benefits are $189.9 million in reduced operating costs, $44.4 million in climate benefits, and $80.8 million in health benefits. In this case, the net benefit would amount to $224.0 million per year.

TABLE V.22—ANNUALIZED BENEFITS AND COSTS OF PROPOSED ENERGY CONSERVATION STANDARDS FOR CIRCULATOR PUMPS (TSL 2)

	Million (2021$/year)		
	Primary estimate	Low-net-benefits estimate	High-net-benefits estimate
3% discount rate:			
Consumer Operating Cost Savings	189.9	185.7	194.0
Climate Benefits*	44.4	44.4	44.4
Health Benefits**	80.8	80.8	80.8
Total Benefits†	315.2	311.0	319.3
Consumer Incremental Product Costs‡	91.2	91.2	91.2
Net Benefits	224.0	219.8	228.1
7% discount rate:			
Consumer Operating Cost Savings	165.8	162.6	168.7
Climate Benefits* (3% discount rate)	44.4	44.4	44.4
Health Benefits**	63.9	63.9	63.9
Total Benefits†	274.1	271.0	277.0
Consumer Incremental Product Costs‡	93.5	93.5	93.5
Net Benefits	180.5	177.4	183.4

Note: This table presents the costs and benefits associated with circulator pumps shipped in 2026–2055. These results include benefits to consumers which accrue after 2055 from the products shipped in 2026–2055.

* Climate benefits are calculated using four different estimates of the global SC-GHG (see section IV.L of this notice). For presentational purposes of this table, the climate benefits associated with the average SC-GHG at a 3 percent discount rate are shown, but the Department does not have a single central SC-GHG point estimate, and it emphasizes the importance and value of considering the benefits calculated using all four SC-GHG estimates. On March 16, 2022, the Fifth Circuit Court of Appeals (No. 22–30087) granted the federal government's emergency motion for stay pending appeal of the February 11, 2022, preliminary injunction issued in *Louisiana* v. *Biden,* No. 21–cv–1074–JDC–KK (W.D. La.). As a result of the Fifth Circuit's order, the preliminary injunction is no longer in effect, pending resolution of the federal government's appeal of that injunction or a further court order. Among other things, the preliminary injunction enjoined the defendants in that case from ''adopting, employing, treating as binding, or relying upon'' the interim estimates of the social cost of greenhouse gases—which were issued by the Interagency Working Group on the Social Cost of Greenhouse Gases on February 26, 2021—to monetize the benefits of reducing greenhouse gas emissions. In the absence of further intervening court orders, DOE will revert to its approach prior to the injunction and present monetized benefits where appropriate and permissible under law.

** Health benefits are calculated using benefit-per-ton values for NO_X and SO_2. DOE is currently only monetizing (for NO_X and SO_2) $PM_{2.5}$ precursor health benefits and (for NO_X) ozone precursor health benefits, but will continue to assess the ability to monetize other effects such as health benefits from reductions in direct $PM_{2.5}$ emissions. See section IV.L of this document for more details.

† Total benefits include consumer, climate, and health benefits. Total benefits for both the 3-percent and 7-percent cases are presented using the average SC-GHG with 3-percent discount rate, but the Department does not have a single central SC-GHG point estimate. DOE emphasizes the importance and value of considering the benefits calculated using all four SC-GHG estimates.

‡ Costs include incremental equipment costs as well as installation costs.

D. Reporting, Certification, and Sampling Plan

Manufacturers, including importers, must use product-specific certification templates to certify compliance to DOE. As discussed previously, DOE is not proposing to amend the product-specific certification requirements for pumps (10 CFR 429.59) to address circulator pumps in this NOPR. DOE may consider certification reporting requirements for circulator pumps in a separate rulemaking.

VI. Procedural Issues and Regulatory Review

A. Review Under Executive Orders 12866 and 13563

Executive Order (''E.O.'') 12866, ''Regulatory Planning and Review,'' as supplemented and reaffirmed by E.O. 13563, ''Improving Regulation and Regulatory Review, 76 FR 3821 (Jan. 21, 2011), requires agencies, to the extent permitted by law, to (1) propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs (recognizing that some benefits and costs are difficult to quantify); (2) tailor regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations; (3) select, in choosing among alternative regulatory approaches, 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 specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public. DOE emphasizes as well that E.O. 13563 requires agencies to use the best available techniques to quantify anticipated present and future benefits and costs as accurately as possible. In its guidance, the Office of Information and Regulatory Affairs (''OIRA'') in the Office of Management and Budget (''OMB'') has emphasized that such techniques may include identifying changing future compliance costs that might result from technological innovation or anticipated behavioral changes. For the reasons stated in the preamble, this proposed/final regulatory action is consistent with these principles.

Section 6(a) of E.O. 12866 also requires agencies to submit ''significant regulatory actions'' to OIRA for review. OIRA has determined that this proposed regulatory action constitutes a ''significant regulatory action'' within the scope of section 3(f)(1) of E.O. 12866. Accordingly, pursuant to section 6(a)(3)(C) of E.O. 12866, DOE has provided to OIRA an assessment, including the underlying analysis, of benefits and costs anticipated from the proposed regulatory action, together with, to the extent feasible, a quantification of those costs; and an assessment, including the underlying analysis, of costs and benefits of potentially effective and reasonably feasible alternatives to the planned regulation, and an explanation why the planned regulatory action is preferable to the identified potential alternatives. These assessments are summarized in this preamble and further detail can be found in the technical support document for this rulemaking.

B. Review Under the Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) requires preparation of an initial regulatory flexibility analysis (''IRFA'') for any rule that by law must be proposed for public comment, unless the agency certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities. As required by E.O. 13272, ''Proper Consideration of Small Entities in Agency Rulemaking,'' 67 FR 53461 (Aug. 16, 2002), DOE published procedures and policies on February 19, 2003, to ensure that the potential impacts of its rules on small entities are properly considered during the rulemaking process. 68 FR 7990 (Feb. 19, 2003). DOE has made its procedures and policies available on the Office of the General Counsel's website (*www.energy.gov/gc/office-general-counsel*). DOE has prepared the following IRFA for the products that are the subject of this rulemaking.

1. Description of Reasons Why Action Is Being Considered

The January 2016 TP final rule and the January 2016 ECS final rule implemented the recommendations of the Commercial and Industrial Pump Working Group (''CIPWG'') established through the Appliance Standards Rulemaking Federal Advisory Committee (''ASRAC'') to negotiate standards and a test procedure for general pumps. (Docket No. EERE–2013–BT–NOC–0039) The CIPWG approved a term sheet containing recommendations to DOE on appropriate standard levels for general pumps, as well as recommendations addressing issues related to the metric and test procedure for general pumps (''CIPWG recommendations''). (Docket No. EERE–2013–BT–NOC–0039, No. 92) Subsequently, ASRAC approved the CIPWG recommendations. The CIPWG recommendations included initiation of a separate rulemaking for circulator pumps. (Docket No. EERE–2013–BT–NOC–0039, No. 92, Recommendation #5A at p. 2)

On February 3, 2016, DOE issued a notice of intent to establish the circulator pumps working group to negotiate a notice of proposed rulemaking (''NOPR'') for energy conservation standards for circulator pumps to negotiate, if possible, Federal standards and a test procedure for circulator pumps and to announce the first public meeting. 81 FR 5658. The CPWG met to address potential energy conservation standards for circulator pumps. Those meetings began on November 3–4, 2016 and concluded on November 30, 2016, with approval of a term sheet (''November 2016 CPWG Recommendations'') containing CPWG recommendations related to energy conservation standards, applicable test procedure, labeling and certification requirements for circulator pumps. (Docket No. EERE–2016–BT–STD–0004, No. 98) As such, DOE has undertaken this rulemaking to consider establishing energy conservation standards for circulator pumps.

2. Objectives of, and Legal Basis for, Rule

EPCA authorizes DOE to regulate the energy efficiency of a number of consumer products and certain industrial equipment. Title III, Part C of EPCA, added by Public Law 95–619, Title IV, section 441(a) (42 U.S.C. 6311–6317, as codified), established the Energy Conservation Program for Certain Industrial Equipment, which sets forth a variety of provisions designed to improve energy efficiency. This equipment includes pumps, the subject of this document. (42 U.S.C. 6311(1)(A))

3. Description on Estimated Number of Small Entities Regulated

For manufacturers of circulator pumps, the Small Business Administration (''SBA'') has set a size threshold, which defines those entities classified as ''small businesses'' for the purposes of the statute. DOE used the SBA's small business size standards to determine whether any small entities would be subject to the requirements of the rule. In 13 CFR 121.201, the SBA sets a threshold of 750 employees or fewer for an entity to be considered as a small business for this category. The equipment covered by this rule are classified under North American Industry Classification System (''NAICS'') code 333914,[79] ''Measuring, Dispensing, and Other Pumping Equipment Manufacturing.''

DOE used publicly available information to identify small businesses that manufacture circulator pumps covered in this rulemaking. DOE identified ten companies that are OEMs of circulator pumps covered by this rulemaking. DOE screened out companies that do not meet the definition of a ''small business'' or are foreign-owned and operated. DOE identified three small, domestic OEMs using subscription-based business information tools to determine the number of employees and revenue of the potential small businesses.

DOE seeks input on its estimate that there are three small business manufacturers of circulator pumps.

4. Description and Estimate of Compliance Requirements Including Differences in Cost, if Any, for Different Groups of Small Entities

This NOPR proposes to adopt energy conservation standards for circulator pumps. To determine the impact on the small OEMs, product conversion costs and capital conversion costs were estimated. Product conversion costs are investments in research, development, testing, marketing, and other non-capitalized costs necessary to make product designs comply with energy conservation standards. Capital conversion costs are one-time investments in plant, property, and equipment made in response to new standards.

DOE estimates there is one small business that does not have any circulator pump models that would meet the proposed standard. The other two businesses both offer circulator pumps that would meet the proposed standard. DOE applied the conversion cost methodology described in section IV.J.2.c of this document to arrive at its estimate of product and capital conversion costs. DOE assumes that all circulator pump manufacturers would spread conversion costs over the two-year compliance timeframe, as standards are expected to require compliance approximately two years after the publication of a final rule. Using publicly available data, DOE estimated the average annual revenue for each of the small businesses. Table VI.1 displays DOE's estimates.

TABLE VI.1—ESTIMATE OF SMALL BUSINESS COMPLIANCE COSTS

Small business manufacturer	Basic models needing re-designed	Conversion costs (2021$ millions)	2 Years of revenue estimate (2021$ millions)	Compliance costs as a percent of 2-year revenue (%)
Manufacturer A	32	44.5	316	14
Manufacturer B	3	3.3	10	32
Manufacturer C	1	1.3	4	33

Additionally, these manufacturers could choose to discontinue their least efficient models and ramp up production of existing, compliant models rather than redesign each of their noncompliant models. Therefore, DOE estimates actual conversion costs could be lower than the estimates developed under the assumption that manufacturers would redesign all noncompliant models. Lastly, DOE notes that all three small businesses are privately owned. Therefore, the exact revenues of these small businesses may vary from DOE's estimates.

DOE seeks input on its estimates of the potential impact to small business manufacturers of circulator pumps. Additionally, DOE requests comment on if any small businesses might exit the circulator pump market in response to the proposed standards, if finalized, or at any other analyzed standard levels and how small businesses would finance, if necessary, the estimated conversion costs.

5. Duplication, Overlap, and Conflict With Other Rules and Regulations

DOE is not aware of any rules or regulations that duplicate, overlap, or conflict with the proposed rule being considered in this action.

6. Significant Alternatives to the Rule

The discussion in the previous section analyzes impacts on small businesses that would result from DOE's proposed rule, represented by TSL 2. In reviewing alternatives to the proposed rule, DOE examined a range of different efficiency levels and their respective impacts to both manufacturers and consumers. DOE examined energy conservation standards set at lower efficiency levels. While lower TSLs would reduce the impacts on small businesses, it would come at the expense of a reduction in energy savings. TSL 1 is estimated to require manufacturers to incur investments that are approximately 93 percent smaller than the investments estimated to be incurred at TSL 2. However, compared to TSL 2, TSL 1 achieves 84 percent less energy savings and 60 percent less consumer net benefits using a 7 percent discount rate.

A manufacturer/importer whose annual gross revenue from all its operations does not exceed $8 million also may apply for an exemption from all or part of any conservation standard for a period not longer than 24 months after the effective date of a final rule establishing the standard. 42 U.S.C. 6295(t).

Additionally, the Department of Energy Organization Act empowers the Secretary of Energy to adjust a rule issued under the EPCA to prevent ''special hardship, inequity, or unfair distribution of burdens'' that may be imposed on a manufacturer/importer as a result of such a rule (42 U.S.C. 7194). The Department of Energy Office of Hearings and Appeals decides whether to grant requests for exceptions.

Based on the presented discussion, DOE believes that TSL 2 would deliver the highest energy savings while mitigating the potential burdens placed on circulator pump manufacturers, including small business manufacturers. Accordingly, DOE does not propose one of the other TSLs considered in the

[79] The size standards are listed by NAICS code and industry description and are available at: *www.sba.gov/document/support-table-size-standards* (Last accessed on May 1, 2022).

analysis, or the other policy alternatives as part of the regulatory impact analysis and included in chapter 17 of the NOPR TSD.

Additional compliance flexibilities may be available through other means. Manufacturers subject to DOE's energy efficiency standards may apply to DOE's Office of Hearings and Appeals for exception relief under certain circumstances. Manufacturers should refer to 10 CFR part 1003 for additional details.

C. Review Under the Paperwork Reduction Act

Under the procedures established by the Paperwork Reduction Act of 1995 (''PRA''), a person is not required to respond to a collection of information by a Federal agency unless that collection of information displays a currently valid OMB Control Number.

OMB Control Number 1910–1400, Compliance Statement Energy/Water Conservation Standards for Appliances, is currently valid and assigned to the certification reporting requirements applicable to covered equipment, including circulator pumps.

DOE's certification and compliance activities ensure accurate and comprehensive information about the energy and water use characteristics of covered products and covered equipment sold in the United States. Manufacturers of all covered products and covered equipment must submit a certification report before a basic model is distributed in commerce, annually thereafter, and if the basic model is redesigned in such a manner to increase the consumption or decrease the efficiency of the basic model such that the certified rating is no longer supported by the test data. Additionally, manufacturers must report when production of a basic model has ceased and is no longer offered for sale as part of the next annual certification report following such cessation. DOE requires the manufacturer of any covered product or covered equipment to establish, maintain, and retain the records of certification reports, of the underlying test data for all certification testing, and of any other testing conducted to satisfy the requirements of part 429, part 430, and/or part 431. Certification reports provide DOE and consumers with comprehensive, up-to date efficiency information and support effective enforcement.

DOE is not proposing certification or reporting requirements for circulator pumps in this NOPR. Instead, DOE may consider proposals to address amendments to the certification requirements and reporting for circulator pumps under a separate rulemaking regarding appliance and equipment certification. DOE will address changes to OMB Control Number 1910–1400 at that time, as necessary. Notwithstanding any other provision of the law, no person is required to respond to, nor shall any person be subject to a penalty for failure to comply with, a collection of information subject to the requirements of the PRA, unless that collection of information displays a currently valid OMB Control Number.

D. Review Under the National Environmental Policy Act of 1969

DOE is analyzing this proposed regulation in accordance with the National Environmental Policy Act of 1969 (''NEPA'') and DOE's NEPA implementing regulations (10 CFR part 1021). DOE's regulations include a categorical exclusion for rulemakings that establish energy conservation standards for consumer products or industrial equipment. 10 CFR part 1021, subpart D, appendix B5.1. DOE anticipates that this rulemaking qualifies for categorical exclusion B5.1 because it is a rulemaking that establishes energy conservation standards for consumer products or industrial equipment, none of the exceptions identified in categorical exclusion B5.1(b) apply, no extraordinary circumstances exist that require further environmental analysis, and it otherwise meets the requirements for application of a categorical exclusion. *See* 10 CFR 1021.410. DOE will complete its NEPA review before issuing the final rule.

E. Review Under Executive Order 13132

E.O. 13132, ''Federalism,'' 64 FR 43255 (Aug. 10, 1999), imposes certain requirements on Federal agencies formulating and implementing policies or regulations that preempt State law or that have federalism implications. The Executive order requires agencies to examine the constitutional and statutory authority supporting any action that would limit the policymaking discretion of the States and to carefully assess the necessity for such actions. The Executive order also requires agencies to have an accountable process to ensure meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications. On March 14, 2000, DOE published a statement of policy describing the intergovernmental consultation process it will follow in the development of such regulations. 65 FR 13735. DOE has examined this proposed rule and has tentatively determined that it would 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. EPCA governs and prescribes Federal preemption of State regulations as to energy conservation for the equipment that is the subject of this proposed rule. States can petition DOE for exemption from such preemption to the extent, and based on criteria, set forth in EPCA. (42 U.S.C. 6316(a) and (b); 42 U.S.C. 6297) Therefore, no further action is required by Executive Order 13132.

F. Review Under Executive Order 12988

With respect to the review of existing regulations and the promulgation of new regulations, section 3(a) of E.O. 12988, ''Civil Justice Reform,'' imposes on Federal agencies the general duty to adhere to the following requirements: (1) eliminate drafting errors and ambiguity, (2) write regulations to minimize litigation, (3) provide a clear legal standard for affected conduct rather than a general standard, and (4) promote simplification and burden reduction. 61 FR 4729 (Feb. 7, 1996). Regarding the review required by section 3(a), section 3(b) of E.O. 12988 specifically requires that Executive agencies make every reasonable effort to ensure that the regulation: (1) clearly specifies the preemptive effect, if any, (2) clearly specifies any effect on existing Federal law or regulation, (3) provides a clear legal standard for affected conduct while promoting simplification and burden reduction, (4) specifies the retroactive effect, if any, (5) adequately defines key terms, and (6) addresses other important issues affecting clarity and general draftsmanship under any guidelines issued by the Attorney General. Section 3(c) of Executive Order 12988 requires Executive agencies to review regulations in light of applicable standards in section 3(a) and section 3(b) to determine whether they are met or it is unreasonable to meet one or more of them. DOE has completed the required review and determined that, to the extent permitted by law, this proposed rule meets the relevant standards of E.O. 12988.

G. Review Under the Unfunded Mandates Reform Act of 1995

Title II of the Unfunded Mandates Reform Act of 1995 (''UMRA'') requires each Federal agency to assess the effects of Federal regulatory actions on State, local, and Tribal governments and the private sector. Public Law 104–4, section 201 (codified at 2 U.S.C. 1531).

For a proposed regulatory action likely to result in a rule that may cause the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector of $100 million or more in any one year (adjusted annually for inflation), section 202 of UMRA requires a Federal agency to publish a written statement that estimates the resulting costs, benefits, and other effects on the national economy. (2 U.S.C. 1532(a), (b)) The UMRA also requires a Federal agency to develop an effective process to permit timely input by elected officers of State, local, and Tribal governments on a proposed ''significant intergovernmental mandate,'' and requires an agency plan for giving notice and opportunity for timely input to potentially affected small governments before establishing any requirements that might significantly or uniquely affect them. On March 18, 1997, DOE published a statement of policy on its process for intergovernmental consultation under UMRA. 62 FR 12820. DOE's policy statement is also available at *www.energy.gov/sites/prod/files/gcprod/documents/umra_97.pdf.*

This rule does not contain a Federal intergovernmental mandate, nor is it expected to require expenditures of $100 million or more in any one year by the private sector.

As a result, the analytical requirements of UMRA do not apply.

H. Review Under the Treasury and General Government Appropriations Act, 1999

Section 654 of the Treasury and General Government Appropriations Act, 1999 (Pub. L. 105–277) requires Federal agencies to issue a Family Policymaking Assessment for any rule that may affect family well-being. This rule would not have any impact on the autonomy or integrity of the family as an institution. Accordingly, DOE has concluded that it is not necessary to prepare a Family Policymaking Assessment.

I. Review Under Executive Order 12630

Pursuant to E.O. 12630, ''Governmental Actions and Interference with Constitutionally Protected Property Rights,'' 53 FR 8859 (Mar. 15, 1988), DOE has determined that this proposed rule would not result in any takings that might require compensation under the Fifth Amendment to the U.S. Constitution.

J. Review Under the Treasury and General Government Appropriations Act, 2001

Section 515 of the Treasury and General Government Appropriations Act, 2001 (44 U.S.C. 3516 note) provides for Federal agencies to review most disseminations of information to the public under information quality guidelines established by each agency pursuant to general guidelines issued by OMB. OMB's guidelines were published at 67 FR 8452 (Feb. 22, 2002), and DOE's guidelines were published at 67 FR 62446 (Oct. 7, 2002). Pursuant to OMB Memorandum M–19–15, Improving Implementation of the Information Quality Act (April 24, 2019), DOE published updated guidelines which are available at *www.energy.gov/sites/prod/files/2019/12/f70/DOE%20Final%20Updated%20IQA%20Guidelines%20Dec%202019.pdf*. DOE has reviewed this NOPR under the OMB and DOE guidelines and has concluded that it is consistent with applicable policies in those guidelines.

K. Review Under Executive Order 13211

E.O. 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use,'' 66 FR 28355 (May 22, 2001), requires Federal agencies to prepare and submit to OIRA at OMB, a Statement of Energy Effects for any proposed significant energy action. A ''significant energy action'' is defined as any action by an agency that promulgates or is expected to lead to promulgation of a final rule, and that (1) is a significant regulatory action under Executive Order 12866, or any successor order; and (2) is likely to have a significant adverse effect on the supply, distribution, or use of energy, or (3) is designated by the Administrator of OIRA as a significant energy action. For any proposed significant energy action, the agency must give a detailed statement of any adverse effects on energy supply, distribution, or use should the proposal be implemented, and of reasonable alternatives to the action and their expected benefits on energy supply, distribution, and use.

DOE has tentatively concluded that this regulatory action, which proposes energy conservation standards for circulator pumps, is not a significant energy action because the proposed standards are not likely to have a significant adverse effect on the supply, distribution, or use of energy, nor has it been designated as such by the Administrator at OIRA. Accordingly, DOE has not prepared a Statement of Energy Effects on this proposed rule.

L. Information Quality

On December 16, 2004, OMB, in consultation with the Office of Science and Technology Policy (''OSTP''), issued its Final Information Quality Bulletin for Peer Review (''the Bulletin''). 70 FR 2664 (Jan. 14, 2005). The Bulletin establishes that certain scientific information shall be peer reviewed by qualified specialists before it is disseminated by the Federal Government, including influential scientific information related to agency regulatory actions. The purpose of the bulletin is to enhance the quality and credibility of the Government's scientific information. Under the Bulletin, the energy conservation standards rulemaking analyses are ''influential scientific information,'' which the Bulletin defines as ''scientific information the agency reasonably can determine will have, or does have, a clear and substantial impact on important public policies or private sector decisions.'' 70 FR 2664, 2667.

In response to OMB's Bulletin, DOE conducted formal peer reviews of the energy conservation standards development process and the analyses that are typically used and has prepared a report describing that peer review.[80] Generation of this report involved a rigorous, formal, and documented evaluation using objective criteria and qualified and independent reviewers to make a judgment as to the technical/scientific/business merit, the actual or anticipated results, and the productivity and management effectiveness of programs and/or projects. Because available data, models, and technological understanding have changed since 2007, DOE has engaged with the National Academy of Sciences to review DOE's analytical methodologies to ascertain whether modifications are needed to improve the Department's analyses. DOE is in the process of evaluating the resulting report.[81]

VII. Public Participation

A. Participation in the Webinar

[80] The 2007 ''Energy Conservation Standards Rulemaking Peer Review Report'' is available at the following website: *energy.gov/eere/buildings/downloads/energy-conservation-standards-rulemaking-peer-review-report-0* (last accessed July 21, 2022).

[81] The report is available at *www.nationalacademies.org/our-work/review-of-methods-for-setting-building-and-equipment-performance-standards.*

The time and date of the webinar meeting are listed in the **DATES** section at the beginning of this document. Webinar registration information, participant instructions, and information about the capabilities available to webinar participants will be published on DOE's website: *www1.eere.energy.gov/buildings/appliance_standards/standards.aspx?productid=66.* Participants are responsible for ensuring their systems are compatible with the webinar software.

B. Procedure for Submitting Prepared General Statements for Distribution

Any person who has an interest in the topics addressed in this proposed rule, or who is representative of a group or class of persons that has an interest in these issues, may request an opportunity to make an oral presentation at the webinar. Such persons may submit to *ApplianceStandardsQuestions@ee.doe.gov.* Persons who wish to speak should include with their request a computer file in WordPerfect, Microsoft Word, PDF, or text (ASCII) file format that briefly describes the nature of their interest in this rulemaking and the topics they wish to discuss. Such persons should also provide a daytime telephone number where they can be reached.

C. Conduct of the Public Meeting

DOE will designate a DOE official to preside at the webinar/public meeting and may also use a professional facilitator to aid discussion. The meeting will not be a judicial or evidentiary-type public hearing, but DOE will conduct it in accordance with section 336 of EPCA (42 U.S.C. 6306). A court reporter will be present to record the proceedings and prepare a transcript. DOE reserves the right to schedule the order of presentations and to establish the procedures governing the conduct of the webinar. There shall not be discussion of proprietary information, costs or prices, market share, or other commercial matters regulated by U.S. anti-trust laws. After the webinar and until the end of the comment period, interested parties may submit further comments on the proceedings and any aspect of the rulemaking.

The webinar will be conducted in an informal, conference style. DOE will a general overview of the topics addressed in this rulemaking, allow time for prepared general statements by participants, and encourage all interested parties to share their views on issues affecting this rulemaking. Each participant will be allowed to make a general statement (within time limits determined by DOE), before the discussion of specific topics. DOE will permit, as time permits, other participants to comment briefly on any general statements.

At the end of all prepared statements on a topic, DOE will permit participants to clarify their statements briefly. Participants should be prepared to answer questions by DOE and by other participants concerning these issues. DOE representatives may also ask questions of participants concerning other matters relevant to this rulemaking. The official conducting the webinar/public meeting will accept additional comments or questions from those attending, as time permits. The presiding official will announce any further procedural rules or modification of the above procedures that may be needed for the proper conduct of the webinar.

A transcript of the webinar will be included in the docket, which can be viewed as described in the *Docket* section at the beginning of this document. In addition, any person may buy a copy of the transcript from the transcribing reporter.

D. Submission of Comments

DOE will accept comments, data, and information regarding this proposed rule before or after the public meeting, but no later than the date provided in the **DATES** section at the beginning of this proposed rule. Interested parties may submit comments, data, and other information using any of the methods described in the **ADDRESSES** section at the beginning of this document.

Submitting comments via www.regulations.gov. The *www.regulations.gov* web page will require you to provide your name and contact information. Your contact information will be viewable to DOE Building Technologies staff only. Your contact information will not be publicly viewable except for your first and last names, organization name (if any), and submitter representative name (if any). If your comment is not processed properly because of technical difficulties, DOE will use this information to contact you. If DOE cannot read your comment due to technical difficulties and cannot contact you for clarification, DOE may not be able to consider your comment.

However, your contact information will be publicly viewable if you include it in the comment itself or in any documents attached to your comment. Any information that you do not want to be publicly viewable should not be included in your comment, nor in any document attached to your comment. Otherwise, persons viewing comments will see only first and last names, organization names, correspondence containing comments, and any documents submitted with the comments.

Do not submit to *www.regulations.gov* information for which disclosure is restricted by statute, such as trade secrets and commercial or financial information (hereinafter referred to as Confidential Business Information (''CBI'')). Comments submitted through *www.regulations.gov* cannot be claimed as CBI. Comments received through the website will waive any CBI claims for the information submitted. For information on submitting CBI, see the Confidential Business Information section.

DOE processes submissions made through *www.regulations.gov* before posting. Normally, comments will be posted within a few days of being submitted. However, if large volumes of comments are being processed simultaneously, your comment may not be viewable for up to several weeks. Please keep the comment tracking number that *www.regulations.gov* provides after you have successfully uploaded your comment.

Submitting comments via email, hand delivery/courier, or postal mail. Comments and documents submitted via email, hand delivery/courier, or postal mail also will be posted to *www.regulations.gov.* If you do not want your personal contact information to be publicly viewable, do not include it in your comment or any accompanying documents. Instead, provide your contact information in a cover letter. Include your first and last names, email address, telephone number, and optional mailing address. The cover letter will not be publicly viewable as long as it does not include any comments.

Include contact information each time you submit comments, data, documents, and other information to DOE. If you submit via postal mail or hand delivery/courier, please provide all items on a CD, if feasible, in which case it is not necessary to submit printed copies. No telefacsimiles (''faxes'') will be accepted.

Comments, data, and other information submitted to DOE electronically should be provided in PDF (preferred), Microsoft Word or Excel, WordPerfect, or text (ASCII) file format. Provide documents that are not secured, that are written in English, and that are free of any defects or viruses. Documents should not contain special characters or any form of encryption and, if possible, they should carry the electronic signature of the author.

Campaign form letters. Please submit campaign form letters by the originating organization in batches of between 50 to 500 form letters per PDF or as one form letter with a list of supporters' names compiled into one or more PDFs. This reduces comment processing and posting time.

Confidential Business Information. Pursuant to 10 CFR 1004.11, any person submitting information that he or she believes to be confidential and exempt by law from public disclosure should submit via email two well-marked copies: one copy of the document marked ''confidential'' including all the information believed to be confidential, and one copy of the document marked ''non-confidential'' with the information believed to be confidential deleted. DOE will make its own determination about the confidential status of the information and treat it according to its determination.

It is DOE's policy that all comments may be included in the public docket, without change and as received, including any personal information provided in the comments (except information deemed to be exempt from public disclosure).

E. Issues on Which DOE Seeks Comment

Although DOE welcomes comments on any aspect of this proposal, DOE is particularly interested in receiving comments and views of interested parties concerning the following issues:

(1) DOE requests comment on its approach to exclude SVILs from the scope of this NOPR, and whether DOE should consider standards for any SVILs as part of this rulemaking.

(2) DOE requests comment regarding circulator pump control variety for the purposes of demonstrating compliance with energy conservation standards.

(3) DOE requests comment regarding the proposed scope of energy conservation standards for circulator pumps.

(4) DOE requests comment regarding the present circulator pump-related definitions, and in particular whether any clarifications are warranted.

(5) DOE requests comment regarding the proposal to analyze all circulator pumps within a single equipment class.

(6) DOE requests comment on its proposal not to establish a separate equipment class for on-demand circulator pumps.

(7) DOE requests comment regarding the current and anticipated forward availability of ECMs and components necessary for their manufacture.

(8) DOE requests comment on whether the distribution channels described above and the percentage of equipment sold through the different channels are appropriate and sufficient to describe the distribution markets for circulator pumps. Specifically, DOE requests comment and data on online sales of circulator pumps and the appropriate channel to characterize them.

(9) DOE seeks comment on the approach and inputs used to develop no-new standards case efficiency distribution.

(10) DOE seeks comment on the approach and inputs used to develop no-new standards case shipments projections.

(11) DOE seeks comment on the approach and inputs used to develop the different standards case shipments projections.

(12) DOE requests comment on the rebound effect specifically for circulator pumps, including the magnitude of any rebound effect and data sources specific to circulator pumps.

(13) DOE seeks input on its estimates of product and capital conversion costs associated with manufacturing circulator pumps at the potential energy conservation standard.

(14) DOE requests comment on its estimates of domestic employment for circulator pump manufacturing in the presence of an energy conservation standards.

(15) DOE seeks input on its estimate that there are three small business manufacturers of circulator pumps.

(16) DOE seeks input on its estimates of the potential impact to small business manufacturers of circulator pumps. Additionally, DOE requests comment on if any small businesses might exit the circulator pump market in response to the proposed standards, if finalized, or at any other analyzed standard levels and how small businesses would finance, if necessary, the estimated conversion costs.

(17) Additionally, DOE welcomes comments on other issues relevant to the conduct of this proposed rulemaking that may not specifically be identified in this document.

VIII. Approval of the Office of the Secretary

The Secretary of Energy has approved publication of this notice of proposed rulemaking and announcement of public meeting.

List of Subjects in 10 CFR Part 431

Administrative practice and procedure, Confidential business information, Energy conservation test procedures, Reporting and recordkeeping requirements.

Signing Authority

This document of the Department of Energy was signed on November 21, 2022, by Francisco Alejandro Moreno, Acting Assistant Secretary for Energy Efficiency and Renewable Energy, pursuant to delegated authority from the Secretary of Energy. That document with the original signature and date is maintained by DOE. For administrative purposes only, and in compliance with requirements of the Office of the Federal Register, the undersigned DOE Federal Register Liaison Officer has been authorized to sign and submit the document in electronic format for publication, as an official document of the Department of Energy. This administrative process in no way alters the legal effect of this document upon publication in the **Federal Register**.

Signed in Washington, DC, on November 22, 2022.

Treena V. Garrett,

Federal Register Liaison Officer,U.S. Department of Energy.

For the reasons set forth in the preamble, DOE proposes to amend part 431 of chapter II, subchapter D, of title 10 of the Code of Federal Regulations, as set forth below:

PART 431—ENERGY EFFICIENCY PROGRAM FOR CERTAIN COMMERCIAL AND INDUSTRIAL EQUIPMENT

■ 1. The authority citation for part 431 continues to read as follows:

Authority: 42 U.S.C. 6291–6317; 28 U.S.C. 2461 note.

■ 2. Amend § 431.465 by revising the section heading and adding paragraph (i) to read as follows:

§ 431.465 Circulator pumps energy conservation standards and their compliance dates.

* * * * *

(i) Each circulator pump that is manufactured starting on [*date 2 years after publication of the final in the* **Federal Register**] and that meets the criteria in paragraphs (i)(1) through (i)(2) of this section must have a circulator energy index (''CEI'') rating (as determined in accordance with the test procedure in § 431.464(c(2)) of not more than 1.00 using the instructions in paragraph (i)(3) of this section and with a control mode as specified in paragraph (i)(4) of this section:

(1) Is a clean water pump as defined in § 431.462.

(2) Is not a submersible pump or a header pump, each as defined in § 431.462.

(3) The relationships in this paragraph (i)(3) are necessary to calculate maximum CEI.

(i) Calculate CEI according to the following equation, as specified in section F.1 of appendix D to subpart Y of part 431:

$$CEI = \frac{\mathrm{CER}}{CER_{STD}}$$

Where:

CEI = the circulator energy index (dimensionless);

CER = the circulator energy rating, determined in accordance with section F.1 of appendix D to subpart Y of part 431 (hp); and

CER_{STD} = the CER for a circulator pump that is minimally compliant with DOE's energy conservation standards with the same hydraulic horsepower as the rated pump, determined in accordance with paragraph (i)(3)(ii) of this section (hp).

(ii) Calculate CER_{STD} according to the following equation:

$$CER_{STD} = \sum_{i} \omega_i \left(P_i^{in,STD}\right)$$

Where:

CER_{STD} = the CER for a circulator pump that is minimally compliant with DOE's energy conservation standards with the same hydraulic horsepower as the rated pump, determined in accordance with paragraph (i)(3)(ii) of this section (hp);

i = the index variable of the summation notation used to express CER_{STD} as described in the following table, in which i is expressed as a percentage of circulator pump flow at best efficiency point, determined in accordance with the test procedure in § 431.464(c)(2):

i
25%
50%
75%
100%

(dimensionless); and

ω_i = the weighting factor at each corresponding test point, *i*, as described in the following table:

i	Corresponding ω_i
25%	.25
50%	.25
75%	.25
100%	.25

(dimensionless); and

$P_i^{in,STD}$ = the reference power input to the circulator pump driver at test point *i*, calculated using the equations and method specified in paragraph (i)(3)(iii) of this section (hp).

(iii) Calculate $P_i^{in,STD}$ according to the following equation:

$$P_i^{in,STD} = \frac{P_{u,i}}{\alpha_i * \frac{\eta_{WTW,100\%}}{100}}$$

Where:

$P_i^{in,STD}$ = the reference power input to the circulator pump driver at test point *i* (hp);

$P_{u,i}$ = circulator pump basic model rated hydraulic horsepower determined in accordance with 10 CFR 429.59(a)(2)(i) (hp);

α_i = part load efficiency factor at each test point as described in the following table:

i	Corresponding α_i
25%	0.4843
50%	0.7736
75%	0.9417
100%	1

(dimensionless); and

$\eta_{WTW,100\neq}$ = reference circulator pump wire-to-water efficiency at best efficiency point at the applicable energy conservation standard level, as described in the following table as a function of circulator pump basic model rated hydraulic horsepower, $P_{u,100\neq}$ (%):

$P_{u,100\%}$	$\eta_{WTW,100\%}$
<1	A*ln($P_{u,100\%}$+B)+C.
≥1	67.79%.

Where A, B, and C are mathematical constants as specified in the following table:

A	B	C
10.00	.001141	67.78

(4) A circulator pump subject to energy conservation standards as described in this paragraph (i) must achieve the maximum CEI as described in paragraph (i)(3)(i) of this section and in accordance with the test procedure in § 431.464(c)(2) in the least consumptive control mode in which it is capable of operating.

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Part IV

Department of the Interior

Bureau of Indian Affairs

25 CFR Part 293

Class III Tribal State Gaming Compacts; Proposed Rule

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

25 CFR Part 293

[2231A2100DD/AAKC001030/A0A501010.999900]

RIN 1076–AF68

Class III Tribal State Gaming Compacts

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Proposed rule.

SUMMARY: The Bureau of Indian Affairs (BIA) seeks input on changes to its regulations governing the review and approval of Tribal-State gaming compacts. The revisions would add factors and clarify how the Department reviews ''Class III Tribal-State Gaming Compacts'' (Tribal-State gaming compacts or compacts).

DATES: Interested persons are invited to submit comments on or before March 1, 2023.

ADDRESSES: You may submit comments by any one of the following methods.

• *Federal eRulemaking Portal:* Please upload comments to *http://www.regulations.gov* by using the ''search'' field to find the rulemaking and then following the instructions for submitting comments.

• *Email:* Please send comments to *consultation@bia.gov* and include ''RIN 1076–AF68, 25 CFR part 293'' in the subject line of your email.

• *Mail:* Please mail comments to Indian Affairs, RACA, 1001 Indian School Road NW, Suite 229, Albuquerque, NM 87104.

FOR FURTHER INFORMATION CONTACT: Oliver Whaley, Director, Office of Regulatory Affairs and Collaborative Action (RACA), Office of the Assistant Secretary—Indian Affairs; Department of the Interior, telephone (202) 738–6065, *RACA@bia.gov.*

SUPPLEMENTARY INFORMATION: This proposed rule is published in exercise of authority delegated by the Secretary of the Interior to the Assistant Secretary—Indian Affairs (Assistant Secretary; AS–IA) by 209 DM 8.

Table of Contents

I. Statutory Authority

In enacting IGRA, Congress delegated authority to the Secretary to review compacts to ensure that they comply with IGRA, other provisions of Federal law that do not relate to jurisdiction over gaming on Indian lands, and the trust obligations of the United States. 25 U.S.C. 2710(d)(8)(B)(i)–(iii).

II. Executive Summary

The Department of the Interior (Department) is considering revisions to its regulations governing the review and approval of Tribal-State gaming compacts (25 CFR part 293). The revisions would add factors and clarify how the Department reviews ''Class III Tribal-State Gaming Compacts'' (Tribal-State gaming compacts or compacts).

The Department's current regulations do not identify the factors the Department considers; rather, those factors are contained in a series of decision letters issued by the Department dating back to 1988. Evolution in the gaming industry and ongoing litigation highlight the need for the Department to clarify how it will analyze Tribal-State gaming compacts to determine whether they comply with the Indian Gaming Regulatory Act of 1988 (IGRA), 25 U.S.C. 2701, *et. seq.,* other provisions of Federal law that does not relate to jurisdiction over gaming on Indian lands, or the trust obligations of the United States to Indians.

III. Background

In 1988 the Indian Gaming Regulatory Act acknowledged that many Tribes were already engaged in gaming, and placed limits on Tribes' sovereign right to conduct gaming. It sought to ensure that Indian Tribes are the primary beneficiaries of the gaming operation, but also authorized State governments to play a limited role in the regulation of class III Indian gaming by negotiating agreements with Tribes called ''Class III Tribal-State Gaming Compacts'' (class III gaming compacts or compacts). Congress sought to strike a balance between Tribal sovereignty and States' interests in regulating gaming and ''shield it from organized crime and other corrupting influences.'' 25 U.S.C. 2702(2).

At the time of IGRA's enactment, Indian gaming represented an approximately $121 million segment of the total United States gaming industry, while Nevada casinos reported approximately $4.1 billion in gross gaming revenue.[1] By the end of fiscal year 2021, Indian gaming represented an approximately $39 billion segment of the total United States gaming industry, with commercial gaming reporting $53 billion.[2] In the Casino City's Indian Gaming Industry Report 2018 Edition, Allen Meister, Ph.D. of Meister Economic Consulting, estimated that Indian Gaming gross gaming revenue for 2016 of approximately $31.5 billion represented a total economic contribution of $105.4 billion across the U.S. economy.

In line with the growth in Indian gaming, State licensed commercial gaming and State lotteries have also experienced growth. In the early 1980's when Congress began considering legislation addressing Indian gaming, two States had legalized commercial casino gaming and seventeen had State run lotteries. By 2017, twenty-four States had legalized commercial casino gaming resulting in approximately 460 commercial casino locations, excluding locations with State licensed video lottery terminals, animal racetracks without gaming machines, and card rooms. In 2017, the gross gaming revenue for the commercial casino industry represented approximately $40.28 billion and generated approximately $9.2 billion in gaming tax revenue. Further, 44 States were operating State lotteries in 2017.

The expansion of State lotteries and State licensed commercial gaming can place Tribes and States in direct competition for market share. Also, advancements in gaming technology and changes in State and Federal gaming law since the passage of IGRA

[1] *See, e.g.,* ''The Economic Impact of Tribal Gaming: A State-By-State Analysis,'' by Meister Economic Consulting and American Gaming Association dated November 8, 2018.

[2] *See, e.g.,* ''The Nation Indian Gaming Commission's annual gross gaming revenue report for 2021;'' *see also* American Gaming Association's press release ''2021 Commercial Gaming Revenue Shatters Industry Records, reaches $53B.''

has shaped the compact negotiation process. As a result, class III gaming compacts have expanded in scope and complexity as the parties seek mutually beneficial provisions. However, IGRA did not anticipate the compact negotiation process would be between competitors, rather sovereign governments seeking to regulate gaming.

Through IGRA, Congress required Tribes to enter into a compact with a State to conduct class III gaming. 25 U.S.C. 2710(d)(1)(C). IGRA requires States to negotiate class III gaming compacts in good faith, limits the scope of bargaining for class III gaming compacts, and prohibits States from using the process to impose any tax, fee, charge, or other assessment on Tribal gaming operations. 25 U.S.C. 2710(d)(3)(A); 2710(d)(3)(C); and 2710(d)(4).

Under IGRA, the Department has 45 days to complete its review and either approve or disapprove a class III gaming compact. If the Department takes no action within that 45-day period, the Tribal-State gaming compact is considered approved by operation of law—to the extent that it is consistent with IGRA. In order for a compact to take effect, notice of its approval must be published in the **Federal Register**.

The regulations that codify the Department's review process for Tribal-State gaming compacts are found at 25 CFR part 293 and were promulgated in 2008 (''2008 Regulations''). 73 FR 74004 (Dec. 5, 2008). The Department's 2008 Regulations were designed to ''address[es] the process for submission by Tribes and States and consideration by the Secretary of Class III Tribal-State Gaming Compacts, and [are] not intended to address substantive issues.'' 73 FR 74004–5. The Department's consideration of substantive issues appears in a number of decision letters. In addition, a body of case law has developed addressing the appropriate boundaries of class III gaming compacts. Through this rule making, the Department seeks to codify longstanding Departmental policies and interpretation of case law in the form of substantive regulations which would provide certainty and clarity on how the Secretary will review certain provisions in a compact.

On March 28, 2022, the Department published a Dear Tribal Leader Letter announcing Tribal consultation pursuant to the Department's consultation policy and under the criteria in E.O. 13175, regarding proposed changes to 25 CFR part 293. The Department held two listening sessions and four formal consultation sessions. The Department also accepted written comments until June 30, 2022.

The Dear Tribal Leader Letter included a Consultation Draft of the proposed revisions to 25 CFR part 293 (hereinafter Consultation Draft); a Consultation Summary Sheet of Draft Revisions to part 293; and a redline reflecting proposed changes to the 2008 Regulations. The Dear Tribal Leader Letter asked for comments on the Consultation Draft as well as responses to seven consultation questions.

The Department received a number of written and verbal comments from Tribal leaders and Tribal advocacy groups. The Department also received written comments from non-Tribal entities which are not addressed in the Tribal consolation comment and response but will be included and addressed as part of the public comment record.

IV. Summary of Comments Received

A. General Comments

Several commenters commented on the process and timing of the proposed rulemaking process. Some requested additional consultations during the rulemaking process, some requested the Department engage in extensive consultations equating to negotiated rulemaking, and others encouraged the Department to proceed with the rulemaking expeditiously.

The Department acknowledges the comments. The Department seeks to balance robust consultation with expeditious processing of the rulemaking. The Department held four virtual consultation sessions, two in-person listening sessions, and is providing additional opportunities for comment on the proposed regulations, which reflect the significant input of Tribal leaders during the scheduled consultation sessions and their written comments.

A number of commenters responded to the Department's first consultation question: ''[d]o the draft revisions increase certainty and clarity in the Secretary's compact review process? Are there additional ways to increase certainty and clarity?'' Commenters expressed support for the proposed revisions to part 293 and noted the Consultation Draft appeared to codify longstanding Departmental policies and interpretation of case law in the form of substantive regulations which would provide certainty and clarity on how the Secretary will review certain provisions in a compact. Commenters also provided a number of specific suggested improvements to specific propose sections, including expressing concerns that some provisions as written are overly broad or vague and may cause confusion. Other commenters cautioned the Department should not apply the proposed regulations in a rigid or paternalistic manner and when possible, defer to a Tribe's sovereign decision making.

The Department acknowledges the comments. The Department seeks to clarify and enforce the proper scope of compacts negotiated under IGRA while deferring to and respecting Tribes' sovereign decision making. The proposed regulations codify existing limitations on Tribes and States negotiating compacts pursuant to IGRA. The Department has addressed specific suggested improvements in the relevant sections below including narrowing some provisions.

A number of commenters responded to the Department's second consultation question: ''[d]o the draft revisions provide sufficient guidance to parties engaged in compact negotiations? Are there ways to provide additional guidance?'' Commenters expressed support for the Consultation Draft and opined that the proposed new substantive provisions would improve the guidance for negotiating parties. Commenters also recommended the Department include in the proposed rule a codification of the Department's longstanding practice of offering ''technical assistance'' to negotiating parties. Other commenters noted ''sufficient guidance'' was a laudable but ultimately unachievable goal. One commenter expressed concern with the Consultation Draft and argued the proposed substantive provisions are cumbersome, unnecessary, and would result in increased requests for technical assistance as Tribes negotiate with State and local governments as required by IGRA.

The Department acknowledges the comments. The Department addresses technical assistance in a separate comment summary and response below. The Department notes the proposed substantive provisions reflect a codification of longstanding Department policy and case law, including the proper scope of a compact. The Department notes intergovernmental agreements between Tribes and States, or local governments can be beneficial, however, Congress provided a narrow scope of topics Tribes and States may include when negotiating a Tribal-State gaming compact.

Commenters requested clarification on whether the proposed regulations would impact ongoing negotiations.

The Department notes the Consultation Draft, and the proposed regulations are prospective and reflect a codification of existing Departmental policy, past precedent, and case law. The Consultation Draft has been made public and the Department encourages Tribes and States that are engaged in negotiations to review the Consultation Draft and the proposed regulations.

A number of commenters requested the Department clarify the effective date of the proposed substantive provisions and questioned whether they would be retroactive. Commenters requested clarification when parties may submit under the new regulations once promulgated. One commenter provided proposed text for a section addressing the effective date and grandfather clause.

The Department has accepted the proposed regulatory text in part and added a section to the proposed rule addressing the effective date of the proposed regulations. The new section is numbered § 293.30. IGRA limits the review period to approve or disapprove compacts or amendments to 45 days. As a result, the Department cannot retroactively approve or disapprove compacts or amendments after the 45-day review period has run.

A number of commenters questioned the Secretary's authority to promulgate substantive regulations interpreting IGRA's scope of compact negotiations. Commenters further questioned the Secretary's authority to determine evidence of bad faith noting IGRA delegated that role to the courts and requested clarification on how the Secretary will find bad faith.

The Secretary has authority to promulgate these regulations on the procedures for the submission and review of compacts and amendments based on the statutory delegation of powers contained in IGRA and 25 U.S.C. 2, and 9. In enacting IGRA, Congress delegated authority to the Secretary to review compacts to ensure that they comply with IGRA, other provisions of Federal law that do not relate to jurisdiction over gaming on Indian lands, and the trust obligations of the United States. 25 U.S.C. 2710(d)(8)(B)(i)–(iii). IGRA establishes the parameters for topics that may be the subject of compact and amendment negotiations and included in compacts. Thus, in reviewing submitted compacts and amendments, the Secretary is vested the authority to determine whether the compacts contain impermissible topics. The Department recognizes that section 2710(d)(7)(A)(I) vests jurisdiction in district courts over any causes of action . . . arising from the failure of a State . . . to conduct [ ] negotiations in good faith.'' Therefore, the Department has replaced the phrase ''evidence of bad faith'' with the phrase ''evidence of a violation of IGRA'' in the proposed rule. This change harmonizes the Department's regulations, with IGRA's plain language, is prescribing those topics, as addressed by IGRA, that may provide evidence of a violation of IGRA and which a court may find as evidence of bad faith negotiations to assist Tribes with their negotiations.

A number of commenters requested the Department include a ''*Seminole* Fix'' in the proposed rule, referencing the decision by Supreme Court of the United States in *Seminole Tribe* v. *Florida,* 517 U.S. 44 (1996), holding Congress could not waive a State's sovereign immunity through IGRA. Some commenters recommended the Department provide technical amendments to 25 CFR part 291 in response to *Texas* v. *United States* (Traditional Kickapoo Tribe), 497 F.3d 491 (5th Cir. 2007) and *New Mexico* v. *United States* (Pueblo of Pojoaque), 854 F.3d 1207 (10th Cir. 2017). Commenters stated the Fifth Circuit and the Tenth Circuit found part 291 did not provide for an independent forum to make the threshold finding that the subject State failed to conclude negotiations in good faith and therefore part 291 was too far adrift from Congressional intent to be allowed to stand. Other commenters recommended providing a mechanism for the Department to seek intervention by the Department of Justice when States raise their 11th Amendment Immunity to a Tribe's challenge of bad faith negotiations under IGRA. Commenters noted without a workable *Seminole* fix, Tribes are often at the mercy of the States who are often the Tribe's gaming competitor and seek to undermine Tribal sovereignty. Commenters noted some Tribes are forced to either accept a State's demand for improper provisions or revenue sharing, or risk a notice of violation and closure for operating without a compact.

The Department notes a minority of circuits have invalidated the Department's part 291 Regulations, which were promulgated to provide Tribes with Secretarial Procedures in response to the Supreme Court's decision in *Seminole Tribe of Florida* v. *Florida,* 517 U.S. 44 (1996), which found that Congress lacked the authority to subject States to suits by Indian Tribes under IGRA. The Department is considering all avenues including technical amendments to part 291. The proposed part 293 regulations reflect the Department's efforts to ensure all Tribes may benefit from the goals of IGRA while enforcing IGRA's limited scope of compacts. The inclusion of clear guidance and codification of key tests as well as articulating situations that may be evidence of a violation of IGRA and therefore evidence of bad faith negotiations is a step in this direction. The Department declines to codify a formal process by which Tribes may submit evidence of bad faith in negotiations to the Department for its consideration and referral to the Department of Justice. The Department has long coordinated with the Department of Justice and the National Indian Gaming Commission regarding enforcement or non-enforcement of IGRA's requirement that a Tribe conduct class III gaming pursuant to a compact or secretarial procedures.[3] The Department will continue to coordinate with the Department of Justice and the National Indian Gaming Commission regarding enforcement of IGRA.

Several commenters requested the Department include additional examples of ''bad faith'' including: take it or leave it compacts; a State's refusal to offer substantially similar compacts to all Tribes in the State; and a State's refusal to negotiate a compact or amendment until an existing compact is set to expire.

The Department acknowledges these may be examples of bad faith negotiations under IGRA. The Department has included in the proposed rule several provisions which the Department considers to be evidence of a violation of IGRA. The Department will continue to coordinate with the Department of Justice and the National Indian Gaming Commission regarding enforcement of IGRA.

Several commenters requested the Department provide notice to the Department of Justice when a compact is disapproved and request the Department of Justice file a bad faith lawsuit against the State on behalf of the Tribe.

On its face, the disapproval of a compact or amendment is not evidence of bad faith negotiations. If, however, the Tribe provides evidence that the State forced the Tribe to include the disapproved provision, the Department may request the Department of Justice file a bad faith lawsuit on behalf of the Tribe in certain situations.

Several commenters requested the Department publish all compact decision letters as well as deemed approval letters in an accessible index.

[3] *See, e.g.,* Statement of Indian Gaming in New Mexico, DOJ 95–459 (August 28, 1995); Statement of Indian Gaming in New Mexico, DOJ 95–553 (October 27, 1995); and Justice Department and California announce plan for orderly transition to legal Indian Gaming, DOJ 98–102 (March 6, 1998).

The Department acknowledges the comments. The Department strives to publish all compact decision letters as well as deemed approval letters on the Office of Indian Gaming's website, which includes an accessible index.

A number of commenters requested the Department include in the proposed rule a formal codification of the Office of Indian Gaming's practice of providing technical assistance to Tribes and States. Some commenters requested a fixed timeline for the Department to issue a technical assistance letter. Other commenters requested the Department include the option for a 'legal opinion' or formal Departmental action in response to some requests for technical assistance.

The Department declines to accept the recommendation. Technical assistance is neither a 'pre-determination' nor 'legal guidance,' rather it is often an explanation of past precedent and interpretation of case law. The Department notes Tribes and States have presented a wide range of unique questions to the Office of Indian Gaming, which may require extensive policy and legal research. Further, depending on the parties' needs and the scope of their requests, some may prefer verbal technical assistance over written technical assistance. The Department will continue to provide technical assistance.

Several commenters discussed their experiences negotiating compacts with States or seeking to enforce disputes under their compacts. Other commenters discussed the importance of Indian gaming to their Tribes as a source of revenue, job growth, and economic self-sufficiency.

The Department acknowledges these comments.

Several commenters discussed legal articles, including work by former Assistant Secretary—Indian Affairs Kevin Washburn.

The Department acknowledges these comments.

Several commenters recommended the Department quote IGRA's statutory language rather than paraphrase the statute as that can result in unintended changes. A commenter recommended the Department narrowly tailor the proposed substantive provisions. Other commenters also noted a primary concern is the definition of gaming activity in § 293.2(d) and used in § 293.23 of the Consultation Draft, § 293.24 of the proposed draft regulations.

The Department adhered closely to the statutory text in the Consultation Draft and the proposed substantive provisions codify longstanding Departmental policy and case law. The Department notes the term ''gaming activity'' is not defined in IGRA. As discussed below, the Department has revised the definition of ''gaming activity'' in § 293.2, as well as addressed it in § 293.24.

Consultation Question: Should the draft revisions include provisions that facilitate Statewide remote wagering or internet gaming?

A number of commenters responded to the Department's sixth consultation question: ''[s]hould the draft revisions include provisions that facilitate Statewide remote wagering or internet gaming?'' The overwhelming majority of commenters agreed that the Department should include provisions relating to i-gaming. Several commenters believe that i-gaming provisions are necessary because Tribes need to be able to compete in the digital industry. Other commenters pointed out that the draft revisions should address i-gaming and provide for its allowance as negotiated between a Tribe and State. Another commenter explained that IGRA encourages agreements between sovereigns.

Several other commenters stated that the State law model of i-gaming is not a substitute for i-gaming under IGRA and Tribes should be able to engage in internet gaming under IGRA. A handful of comments also expressed support for the Department's inclusion but questioned the need to define gaming activity as including the elements of prize, consideration, and chance, as it could potentially be misconstrued in a court ruling that requires all three elements to be present on Indian lands.

Finally, several of the commenters in support of inclusion of i-gaming also praised the Department's i-gaming analysis in the June 21, 2021, Deemed Approved letter to the Seminole Nation. At least three commenters also submitted proposed language for the Department to address i-gaming.

A handful of commenters opposed the Department addressing i-gaming in the draft revisions. One commenter stated that the issue was not ripe for inclusion; another stated that i-gaming was subject to State law and there's no case law to state that the Secretary has power over this topic; another thought that the issue is an unresolved matter of Federal law and the Department should not weigh in; and another believed there is a lack of ability to regulate i-gaming and would harm brick and mortar facilities.

Two commenters did not expressly support or oppose the inclusion of i-gaming; one noted that the Department should further consult with Tribes before making any decisions and the other noted that while the Department's views on the legality of such a provision would be helpful, it is unclear what further provisions would be proposed. Other commenters shared personal experiences and/or legal analysis which helped inform their decision-making.

The Department acknowledges the comments and has added a new section to the proposed rule ''§ 293.29 May a compact of amendment include provisions addressing Statewide remote wagering or internet gaming,'' addressing Statewide remote wagering and internet gaming. The IGRA provides that a Tribe and State may negotiate for ''the application of the criminal and civil laws and regulations of the Indian Tribe or the State that are directly related to, and necessary for, the licensing and regulation of such activity'' and ''the allocation of criminal and civil jurisdiction between the State and the Indian Tribe necessary for the enforcement of such laws and regulations.'' 25 U.S.C. 2710(d)(3)(c)(i)–(ii). The Department's position is that the negotiation between a Tribe and State over Statewide remote wagering or i-gaming falls under these broad categories of criminal and civil jurisdiction. Accordingly, provided that a player is not physically located on another Tribe's Indian lands, a Tribe should have the opportunity to engage in this type of gaming pursuant to a Tribal-State gaming compact.

B. Section Comments

Comments on § 293.1 What is the purpose of this part?

Several commenters recommended the Department revise § 293.1(a) by including the word ''or'' after the word ''and'' so that the relevant provision would read ''[p]rocedures that Indian Tribes and/or States must use when submitting . . . .'' The commenters suggested change would clarify either party may submit compacts or compact amendments.

The Department has accepted this suggested revision and notes that § 293.6 explains either the Tribe or the State may submit the compact or amendment.

Several commenters supported the proposed revisions to § 293.1.

The Department acknowledges the comment.

Comments on § 293.2 How are key terms defined in this part?

Several commenters recommended the Department retain the 2008 Regulation's introductory text for § 293.2 ''[f]or purposes of this part, all terms have the same meaning as set forth in the definitional section of the Indian Gaming Regulatory Act of 1988, 25 U.S.C. 2703 and any amendments thereto.''

The Department declines to accept the recommendation to retain the 2008 Regulation's introductory text for § 293.2. The Department proposed changes to the introductory text in § 293.2 to improve clarity.

One commenter recommended the phrasing ''[i]n addition to terms already defined in IGRA, this part defines the following additional key terms.''

The Department declines to accept the recommendation. One term ''Indian Tribe'' is defined in IGRA at 25 U.S.C. 2703(5) and refined here as ''Tribe.'' The proposed language indicates the defined terms in § 293.2 are all new or additional terms, which could cause confusion.

Several commenters expressed support for the proposed revisions to § 293.2 and noted the new definitions for key terms are consistent with IGRA.

The Department acknowledges the comments.

Comments on § 293.2(a)—Amendment

Several commenters suggested the definition of *Amendment* in § 293.2(a) and as applied in § 293.4 is too broad. Other commenters suggested the Department clarify the definition of *Amendment* to exclude strictly administrative or procedural amendments from review under § 293.4.

The Department has revised § 293.4 to address these and related comments on that section.

One commenter requested the Department revise the definition of *Amendment* to include ''or an amendment to secretarial procedures prescribed under 25 U.S.C. 2710(d)(7)(B)(vii) when such amendment is agreed upon by the Indian Tribe and State.'' The commenter explained this addition would clarify that any such agreements are treated as a ''compact'' or ''compact amendment'' for the purposes of IGRA's 45-day review period.

The Department has accepted the recommendation and include the proposed text in § 293.2(a).

Comments on § 293.2(c)—Extension

Several commenters expressed support for the revised definition of *Extension* in § 293.2(c).

The Department acknowledges the comments.

One commenter recommended the Department remove the words ''or amendment'' from the definition of *Extension* and noted that § 293.5 does not include the words ''or amendment.''

The Department notes the terms ''Compact'' and ''Amendment'' are frequently used interchangeably depending on the underlying facts and needs of the parties to the agreement. For that reason, the Department used the phrase ''compact or amendment'' throughout the Consultation Draft of part 293. The Department has made a conforming edit to § 293.5.

Comments on § 293.2(d)—Gaming Activity

Several commenters recommended the Department revise the definition of ''gaming activity or gaming activities'' in § 293.2(d) by replacing the word ''prize'' with the word ''reward.'' The commenters explained the term 'reward' is the more commonly used term in the Tribal gaming industry.

The Department accepted the recommended revision to § 293.2(e), in part. The definition of *gaming activity or gaming activities* now reads ''*[g]aming activity or gaming activities* means the conduct of class III gaming involving the three required elements of change, consideration, and prize or reward.''

Several commenters expressed concern that including a definition of *Gaming Activity* in part 293 could be construed to require all elements of the gaming activity to occur on a Tribe's Indian lands thereby precluding Tribes from negotiating Statewide mobile or i-gaming in compacts.

The Department acknowledges this concern and has included a new proposed § 292.29 which addresses i-gaming in compacts.

Comments on § 293.2(e)—Gaming Facility

One commenter recommended the Department include a defined term for ''gaming spaces'' consistent with the rational in the Department's 2021 disapprovals of three California compacts. The commenter explained that including ''gaming spaces'' defined term would resolve a logical conflict between the Department's definition of *gaming facility* and 25 U.S.C. 2710(d)(3)(C)(vi), which permits a compact to include ''standards for the . . . maintenance of the gaming facility, including licensing.'' The commenter explained that by defining *gaming facility* as the whole structure for the purposes of building maintenance under the second clause of 25 U.S.C. 2710(d)(3)(C)(vi); and *gaming spaces* for section 2710(d)(3)(C)(i), (ii), the first clause of (vi), and (vii), would provide parties with clarity regarding the appropriate limits of State oversite under IGRA.

The Department accepted the recommendation and has included *gaming spaces* as a defined term and revised the definition of *gaming facility* by moving the clause addressing the gaming spaces to the new paragraph (f) *gaming spaces.* The revised definition of *gaming facility* addresses the commenter's concern regarding building maintenance and licensing under the second clause of 25 U.S.C. 2710(d)(3)(C)(vi).

A number of commenters addressed the clause addressing the gaming spaces in the proposed definition of *gaming facility* in § 293.2(e).

Several commenters recommended the Department replace the phrase ''the spaces that are necessary for conduct of gaming'' with the phrase ''the spaces that are directly related to, and necessary for, the operation of class III gaming activities.'' Commenters explained that phrasing is more consistent with how the Department has described the appropriate reach of the term ''gaming facility'' in a compact.

Several commenters recommended the Department replace the phrase ''including the casino floor'' with the phrase ''such as the casino floor.'' Commenters explained this change would permit the parties to determine which areas should be properly included and which areas should properly be excluded.

Several commenters recommended the Department revise the phrase ''class III gaming device, and storage areas'' by adding the word ''and'' before the phrase and deleting the comma after the word ''device'' so that the phrase would read ''and class III gaming devices and supplies storage areas.'' Another commenter recommended adding the work ''gaming'' before the word ''supplies'' to read ''gaming supplies storage areas.''

Several commenters recommended adding the phrase ''and other secured areas'' at the end of the definition.

Several commenters recommended clarifying that the definition of *gaming facility* excludes areas that merely provide amenities to gaming patrons—hotels, restaurants, and other spaces that are not directly used for the conduct of class III gaming.

The Department has accepted the recommended revisions to the clause addressing the gaming spaces in the definition of *gaming facility* in part. The new definition of *gaming spaces* incorporates the suggested revisions and continues to seek the smallest physical footprint of potential State jurisdiction over a Tribe's land under IGRA. This definition is intended to codify the Department's long-standing narrow read of 25 U.S.C. 2710(d)(3)(C) as applying only to the spaces in which the operation of class III gaming actually takes place. The revised definition of *gaming facility* addresses building maintenance and licensing under the second clause of 25 U.S.C. 2710(d)(3)(C)(vi) and is intended to be narrowly applied to only the building or structure where the gaming activity occurs.[4]

One commenter recommended the Department include the term ''structure'' to reflect the diversity of structures Tribes utilize for the conduct of Gaming.

The Department has accepted the recommended revision to the definition of *gaming facility.* The definition of *gaming facility* in § 293.2(e) now reads ''the physical building or structure, where the gaming activity occurs.

Several commenters recommended the Department include a definition for the term ''project'' in § 293.2, as part of the definition of the term ''gaming facility'' in § 293.2(e). The commenters explained that some States have used the term ''project'' or ''gaming project'' in conjunction with ''gaming facility'' to extend State oversight and taxation through triggering extensive environmental reviews and impact or mitigation payments when a Tribe seeks to develop or expand a ''gaming facility.''

The Department declines to include a definition for the term ''project.'' Proposed revisions to part 293, including the definitions of *gaming facility* and *gaming spaces,* and proposed substantive provisions in §§ 293.24, 293.25, and 293.28 build on the Department's narrow read of the permissible scope of a Tribal State compacts, and is consistent with the Department's disapproval of compacts from the State of California in part due to expansive definitions of ''gaming facility'' and ''project.''

Comments on the Term Necessary for

Several commenters recommended the Department define or otherwise articulate a standard for interpreting the term ''necessary for'' as it is used in 25 U.S.C. 2710(d)(3)(C) and 25 CFR part 293. The commenters further recommended the Department defer to a Tribe's reasonable determination of which provisions in a compact are ''necessary for the operation of class III gaming.''

The Department notes there is not a strict definition for ''necessary,'' therefore, we must look to the context in which it is used in the statute. As used in IGRA, ''necessary'' is a limiting phrase, or one that employs the common law use of ''necessary'' in the strict sense of indispensable or essential.[5] When applying provisions which incorporate ''necessary for'' in IGRA and in part 293 the Department will ask ''is this provision absolutely needed for the Tribe to operate class III gaming?''

Comments on § 293.3 What authority does the Secretary have to approve or disapprove compacts and amendments?

Several commenters supported the proposed revisions to § 293.3, but questioned if the internal cross-reference to § 293.14 is accurate.

The Department acknowledges the comments. The internal cross-reference to § 293.14 appears in the current § 293.3 and the redline reflects a strikeout of ''293.14'' with the updated cite to § 293.15.

Several commenters recommend that § 293.3 cite the statutory authority of the Secretary to approve or disprove a compact or amendment. Commenters noted other sections in part 293 address the baseline requirements of compact execution and submissions.

The Department has revised § 293.3 to remove references to the signatures of the parties.

One commenter recommended the Department revise § 293.3 by adding the phrase: ''and an amendment resulting from another agreement, including, but not limited to, agreements, other documents, dispute resolutions, settlement agreements, or arbitration decisions.''

The Department declines to include the proposed language in § 293.3. The Department notes revisions to §§ 293.4, 293.7, and 293.21, address amendments caused by dispute resolution agreement, arbitration award, settlement agreement, or other resolution of a dispute outside of Federal court.

Several commenters recommended the Department revise § 293.3 by adding the phrase: ''and applicable approvals of both parties.''

The Department declines to include the proposed language in § 293.3. The Department notes revisions to §§ 293.7 and 293.8 address the execution and approval requirements for a compact or amendment.

Comments on § 293.4 Are compacts and amendments subject to review and approval?

Several commenters recommended the Department revise § 293.4 by moving the references to ''agreements or other documents'' from paragraph (a) to paragraph (b) and removing references to the State including its political subdivisions from paragraph (b). Commenters noted these changes would allow a Tribe to determine which documents are not 'amendments.'

The Department accepted the proposed revisions in part. The Department notes that proposed § 293.21 addresses compact amendments arising from dispute resolution procedures and proposed § 293.27 addresses intergovernmental agreements or memoranda of understanding between the Tribe and the State or its political subdivisions. The Department notes the § 293.4 determination process is open to either party consistent with the submission procedures in Subpart B.

Several commenters recommended the Department split § 293.4(b) into a new section addressing ancillary agreements. The commenters noted this proposed section would strike a balance between documents that amend a compact and are properly subject to Secretarial review and documents or agreements between Tribal regulators and State regulators addressing technical implementation of compact terms. The proposed new section would be titled ''[w]hen are ancillary agreements and documents subject to review and approval?'' The proposed new section would include three new paragraphs and contain revisions to the text of § 293.4(b).

The Department accepted the proposed revisions in part and incorporated the proposed ancillary agreement test in § 293.4(b).

Several commenters requested the Department codify a streamlined approach for review and approval of technical amendments.

The Department declines to provide a separate ''streamlined'' procedure for

[4] *See, e.g.,* Letter to the Honorable Peter S. Yucupicio, Chairman, Pascua Yaqui Tribe of Arizona, from the Director, Office of Indian Gaming, dated June 15, 2012, at 5, and fn. 9, discussing the American Recovery & Reinvestment Act of 2009 and the IRS's ''safe harbor'' language to reassure potential buyers that tribally-issued bonds would be considered tax exempt by the IRS because the bonds did not finance a casino or other gaming establishment.

[5] ''Like ordinary English speakers, the common law uses 'necessary' in this strict sense of essential or indispensable.'' *Vorchheimer* v. *Philadelphian Owners Ass'n,* 903 F.3d 100, 106 (3d Cir. 2018) (discussing Congress' use of ''necessary'' in legislation where no definition provided). ''[W]hen Congress wants to loosen necessity to mean just 'sufficiently important,' it uses the phrase 'reasonably necessary.' '' *Id.* at 107; *see Ayestas* v. *Davis,* ____ U.S. ____, 138 S. Ct. 1080, 1093 (2018) (''[18 U.S.C. 3599] appears to use the term 'necessary' to mean something less than essential. The provision applies to services that are 'reasonably necessary,' but it makes little sense to refer to something as being 'reasonably essential.' '').

technical amendments. IGRA provides the Secretary with a 45-day review period, which also applies to technical amendments.

Comments on § 293.4(a)

Several commenters questioned if the Secretary's authority under IGRA extended to 'non-compact' agreements between Tribes and States or local governments. Commenters noted that Tribes often find agreements with local governments addressing a myriad of topics—including payments in leu of taxes, service agreements, and mutual aid agreements—are mutually beneficial and in the Tribe's best interest. Commenters further questioned the Department's inclusion of ''[a]ny agreement which includes provisions for the payment from a Tribe's gaming revenue . . .'' in § 293.27 as requiring review and determination under § 293.4(c), if such agreements are a ''compact'' or ''amendment.''

The Department declines to accept the comments. The Department notes some States have included a requirement in compacts for the Tribe to enter into agreements with local governments often addressing payments by the Tribe for the loss of tax revenue. Some of these agreements are designed to avoid Secretarial review and impose impermissible taxes or other assessments on the Tribes. IGRA at 25 U.S.C. 2710(b)(2)(B) permits a Tribe to utilize net gaming revenue to fund the Tribe's government, provide for general welfare of the Tribe and its members, promote Tribal economic development, to donate to charitable organizations, and help fund operations of local governments. However, IGRA then at 25 U.S.C. 2710(d)(4) prohibits a State and its political subdivisions from imposing any ''tax, fee, charge, or other assessment'' on the Tribe for engaging in class III gaming. The proposed § 293.4(c) process is designed to ensure these agreements receive proper scrutiny and are not the result of a State improperly demanding—through its political subdivisions—a tax, fee, charge, or other assessment.

Several commenters requested the Department narrow the scope of § 293.4. The commenters explained that many compacts anticipate the utilization of ancillary agreements between the Tribe and the State to interpret specific compact terms for the purpose of effective operation and regulation of the day-to-day minutiae of operating class III gaming. Commenters noted that the consultation draft of § 293.4 could be construed to capture internal controls, memorandum of understanding between Tribal and State regulatory and licensing bodies, and other documents utilized by the parties to effectively and efficiently ensure the Tribe's class III gaming operation is in compliance with the compact and with IGRA.

The Department has revised § 293.4 to clarify which documents the Department considers within the definition of ''amendment'' subject to Secretarial review.

Other commenters noted some compacts include mechanisms for the Tribe and the State to add games pursuant to changes in State or Federal law without amending the Compact and noted that the consultation draft of § 293.4 could be construed to capture the Tribe and the State's documentation of games added pursuant to changes in State or Federal law.

The Department has revised § 293.4 to clarify which documents the Department considers within the definition of ''amendment'' subject to Secretarial review.

Several commenters requested the Department revise § 293.4(a) for consistency with § 293.21 by exempting Federal court decisions from Secretarial review as an 'amendment.'

The Department has revised § 293.4 for consistency with § 293.21 to clarify which documents the Department considers within the definition of ''amendment'' subject to Secretarial review.

Several commenters raised concerns that the Department's inclusion of ''dispute resolution, settlement agreements, or arbitration decisions'' within § 293.4's list of documents subject to Secretarial review may discourage parties from utilizing potentially cost-effective dispute resolution methods and would increase burdens on the parties. The commenters argued the expansion of Secretarial review to include dispute resolution, settlement agreements, or arbitration decisions may increase uncertainty. Commenters also recommended the Department defer to a Tribe's determination if a document warrants Departmental review.

The Department has revised § 293.4 for consistency with § 293.21 to clarify which documents the Department considers within the definition of ''amendment'' subject to Secretarial review.

Other commenters expressed support for the Department's inclusion of ''dispute resolution, settlement agreements, or arbitration decisions'' within § 293.4's list of documents subject to Secretarial review and noted examples of settlement agreements and arbitration awards which materially change the parties' obligations under the compact in a manner that may conflict with IGRA and would otherwise have been considered an amendment subject to Secretarial review. Commenters noted an example where an arbitration panel decision added a term to the compact changing the Tribe's revenue sharing obligation beyond the compact provisions reviewed by the Secretary. Commenters noted the Tribe determined the arbitration decision amended the compact and sought Secretarial review but was prevented by the State's refusal to certify the arbitration decision as an amendment.

The Department acknowledges the concerns raised by the commenters. The Department notes the proposed changes to part 293 are intended to address these and similar situations. The Department has revised § 293.4 in response to these comments.

Several commenters requested the Department revise § 293.4(a) by removing the phrase ''regardless of whether they are substantive or technical.''

The Department declines the requested revision and notes that phrase is found in the 2008 Regulations at § 293.4(b). When promulgating the 2008 Regulations the Department had proposed an exception for ''technical amendments'' but in response to comments on the 2008 Notice of Proposed Rulemaking, removed that provision. 73 FR 74005 (Dec. 5, 2008). The Department explained many commenters questioned how to determine if an amendment was 'substantive' and subject to Secretarial review, or 'technical' and not subject to Secretarial review.

One commenter recommended the Department clarify § 293.4(a) by moving the words ''agreements or other documents'' after the phrase ''including but not limited to'' along with conforming grammatical edits.

The Department incorporated the suggested edit in the revised § 293.4(a) and (c).

Comments on § 293.4(b)—Which Has Been Renumbered as § 293.4(c)

The Department has renumbered the proposed § 293.4(b) as § 293.4(c) and comments have been edited to reflect the new section number.

Several commenters expressed support for the Department's proposed process in § 293.4(c) to provide parties a determination if an agreement is a ''compact'' or ''amendment'' and must be submitted for review and approval by the Secretary. Commenters noted this proposed process provides Tribes with a similar service as the National Indian Gaming Commission's ''declination letters,'' which determine if an agreement is a ''Management Contract'' requiring approval by the NIGC Chair.

The Department acknowledges the comments.

Several commenters requested the Department amend § 293.4(c) by including a deadline for the Department to review the submitted document and to issue a determination letter.

The Department has added a 60-day review period for a determination under § 293.4.

Other commenters requested the Department clarify if a non-party may submit a request for a § 293.4(c) determination.

The Department notes the existing 2008 Regulations at § 293.6 address the processes by which the parties to a Compact may submit it for Secretarial review. In relevant part, § 293.6 states ''either party [ ] to the compact or amendment can submit.'' The Consultation Draft of § 293.4(c) utilized similar language and stated, ''either party may request in writing a determination . . . if their agreement is a compact or amendment.'' The Department has consistently and will continue to exclude third parties from the submission and review process.

Several commenters requested the Department amend § 293.4(c) to clarify if the Department's determination letter or materials submitted pursuant to this review would be used by the Department as the basis for an adverse action against the Tribe. Commenters also requested the Department include in a § 293.4(c) determination letter a discussion of any provisions in the underlying document which may lead to subsequent disapproval as a compact under IGRA.

The Department intends for the § 293.4(c) determination process to provide parties with improved clarity whether their agreement or other document is a compact or amendment, without submitting the document for Secretarial review and approval or disapproval. The Department historically has provided parties with technical assistance as well as deemed approval letters which identify problematic provisions. The Department anticipates a § 293.4(c) determination letter may include similar guidance; however, the Department declines to revise § 293.4(c) to require such guidance.

Several commenters requested the Department clarify how and where a party may submit a request and encouraged the Department to allow flexibility in submitting such requests.

The Department has revised § 293.9 to clarify that compacts, amendments, written requests for a determination pursuant to § 293.4(c), or requests for technical assistance must be submitted to the Office of Indian Gaming at the address listed in § 293.9. The Department further notes that § 293.9 has been revised to include the email address ''*indiangaming@bia.gov*''.

Several commenters requested the Department amend § 293.4(c) to require the Department's determination letter clearly state in the introduction of the letter either: ''Yes. This agreement constitutes a [compact/amendment] requiring secretarial approval'' or ''No. This agreement does not constitute a [compact/amendment] . . . .''

The Department declines to include the requested requirement within the regulatory text of § 293.4(c). The Department is required to utilize plain writing—in other words clear, concise, and well-organized writing. The Department implements this requirement by providing a brief summary of the document submitted and the Department's determination in the introductory section of decision letters.

Several commenters requested the Department revise the concluding sentence of § 293.4(c) to state: ''[t]he Department will issue a letter providing notice of the Secretary's determination.'' Commenters suggested this would reduce potential ambiguity.

The Department has accepted the requested revision to the concluding sentence of § 293.4(c).

Comments on § 293.5 Are extensions to compacts or amendments subject to review and approval?

Several commenters supported the proposed revisions to § 293.5 and noted the revisions reflected the Department's longstanding practice of treating extensions as a type of amendment which is exempted from Secretarial approval prior to publication of a notice in the **Federal Register**.

The Department acknowledges the comments.

Several commenters requested the Department clarify the distinctions between an ''amendment'' and an ''extension'' as defined in § 293.2 and applied in §§ 293.4 and 293.5. Commenters noted an extension may have the effect of changing the ''operation and regulation'' of a Tribe's Class III gaming activities.

The Department has revised § 293.2(c). The 2008 Regulations adopted the provision exempting extensions from Secretarial review in response to a comment on the draft rule, which had proposed to exempt ''technical amendments'' but not substantive amendments or extensions. *See* 73 FR 37909 (July 2, 2008) and 73 FR 74005. Extensions are a form of amendment, which changes only the term of the compact, but not other provisions in the compact.

One commenter suggested the Department provide a mechanism for a Tribe to unilaterally extend an existing compact in the event the Tribe and the State are unable to successfully negotiate an amendment or new compact. The commenter noted such a mechanism would incentivize the State to engage in timely good faith negotiations and protect Tribes from risking the expiration of an existing compact due to a State's negotiation delays.

The Department appreciates the concern raised by the commenter but lacks the authority to provide a mechanism for unilateral compact extensions. We will include this type of provision as a best practice in providing technical assistance.

Several commenters questioned if the parties to an approved compact with an automatic renewal provision or automatic extension provision are subject to § 293.5, when the provisions of the compact are satisfied thereby extending the compact.

The Department notes compacts may have provisions allowing for renewal or extensions of the term of the compact if certain provisions are met. The Department does not consider the renewal or extension of the term of the compact under the very terms of the compact as an *extension* as defined in § 293.2(e) and requiring publication of notice in the **Federal Register** under § 293.5. The Department has revised the definition of *extension* to clarify extensions are new agreements between the parties to extend the compact term rather than the exercise of an existing provision.

Several commenters requested the Department amend § 293.5 to limit the reference to documents required under § 293.8 to paragraph (b) and (c) as required by the 2008 Regulations. Commenters stated the requiring compliance with all of § 293.8 would be a burden on Tribes seeking an extension.

The Department has revised the reference in § 293.5 to 293.8 in response to these comments. Section 293.5 now requires the documents listed in § 293.8(a) through (c). The Department notes the provision in § 293.8(a) reflects the definition of *extension* in § 293.2(e).

Several commenters questioned the necessity for the Department to publish a notice of compact extension in the **Federal Register** in order for the extension to be ''in effect.'' Commenters questioned if the process for extensions may result in undue delay because the extension requires a **Federal Register** document but is exempted from Secretarial review and not subject to the statutory 45-day review period.

The Department disagrees with the comment. An extension is subject to the 45-day statutory review period. Proposed revisions to § 293.5 in the Consultation Draft included clarifying that IGRA requires publication of a notice of extension in the **Federal Register** for the extension to be in effect. The Department notes an extension is an amendment to the *duration* of the compact and under the proposed regulations continues to receive expedited processing.

Several commenters requested the Department revise § 293.5 to require publication of a notice of compact extension within 14 days of the submission of the extension.

The Department declines to revise § 293.5 to include a 14-day deadline for publishing a notice of compact extension in the **Federal Register**. The Department notes an extension is a type of amendment that receives expedited processing. Further § 293.14 addresses timing of publication of notices in the **Federal Register** in compliance with IGRA.

Several commenters requested the Department revise § 293.5 to exempt restated compacts in the same manner as extensions.

The Department declines the requested revision. A restated compact is a new restatement of existing provisions as amended in a compact, and thus, a new compact subject to review. An extension is an amendment that changes only the duration of the compact, and is not subject to review. IGRA limits the Secretary's authority to review and approve or disapprove a compact or amendment to 45 days. The Department encourages parties to utilize restated compacts or amended and restated compacts as a best practice to incorporate a series of amendments into a single document. The Department finds it helpful if the Tribe or State also submits a redlined copy of the restated compact.

Comments on § 293.6 Who can submit a compact or amendment?

Several commenters sought clarification on whether § 293.6, or other provisions in part 293, exclude third party submissions.

The Department has consistently and will continue to exclude third parties from the submission and review process. The Department's longstanding application of § 293.6 is to permit either party to the compact or amendment to submit the required documents for Secretarial review and approval. The Consultation draft of § 293.6 contained minor stylistic edits for clarity and consistency.

Several commenters expressed support for the proposed revisions to § 293.6.

The Department acknowledges the comments.

Comments on § 293.7 When should the Tribe or State submit a compact or amendment for review and approval?

Several commenters requested the Department revise § 293.7 to more accurately reflect the legal status of the document pending secretarial review, and in some instances, how an amendment may be created through compact dispute resolution procedures. One commenter requested the Department replace the phrase ''legally entered into by the parties'' with the phrase ''duly executed by the Tribe and State in accordance with applicable Tribal and State law.'' Another commenter suggested adding the phrase ''or the amendment has been issued by an arbitration panel'' to the end of § 293.7.

The Department notes the Consultation Draft of § 293.7 remained unchanged from the 2008 Regulations. The phrase ''legally entered into'' reflects the requirements of the statutory text in IGRA at 25 U.S.C. 2710(d)(8)(A), and is consistent with the requirements in § 293.8, in compliance with both Tribal law and State law. The Department has revised § 293.7 by adding the phrase ''or is otherwise binding on the parties'' to more accurately reflect how an amendment or other ancillary agreement may be created, as described in § 293.4.

One comment suggested the phrase ''legally entered into by the parties'' in § 293.7 contradicts § 293.14 because the compact does not take effect until it is published in the **Federal Register**.

The Department has revised § 293.7 to state ''duly executed by the Tribe and the State in accordance with applicable Tribal land State law, or is otherwise binding on the parties.'' IGRA requires the compact or amendment to first be entered into by the parties; second, submitted for review by the Secretary; and third, have notice published in the **Federal Register** prior to the compact or amendment being ''in effect.'' 25 U.S.C. 2710(d)(3)(B).

Comments on § 293.8 What documents must be submitted with a compact or amendment?

Several commenters noted the documents required for submission under § 293.8 may contain confidential business information of the Tribe and requested the Department maintain confidentiality of sensitive business information and protect it from release under the Freedom of Information Act.

The Department routinely receives confidential Tribal business information in response to requests for additional information under § 293.8(d) of the 2008 Regulations. This information is protected from public disclosure under exemption 4 of the Freedom of Information Act. Additionally, prior to releasing any requested tribally submitted information, the Department consults with the submitting Tribe to confirm such information is confidential business information and can properly be withheld. The Department recommends that as a best practice, Tribes should notify the Department when confidential information is submitted, so that it can be properly withheld if requested under the Freedom of Information Act.

Several commenters noted the documents required by § 293.8, if not submitted, are grounds of disapproval of a compact under § 293.16(b). Commenters requested clarity on how the Department will determine if the requirements of § 293.8 have been met and if the Department will provide parties opportunities to submit missing documents or cure deficiencies in the submitted documents.

The Department notes that § 293.16(b) clarifies that the Department must inform the parties in writing of any missing documents required by § 293.8.

Several commenters requested the Department revise § 293.8 to include an express waiver the Secretary may invoke if or when either party shows a need for additional flexibility in submitting a compact or amendment. Commenters noted parties to a compact who resort to arbitration or similar dispute resolution may be reluctant to provide the required certification of an arbitration panel decision under § 293.8(b) and (c) in an effort to avoid Secretarial review or enforcement of an unfavorable decision.

The Department declines to include a blanket waiver under § 293.8, but notes the Secretary may consider issuing a discretionary waiver in certain circumstances after consideration of the submitted documents. Certain documents, such as arbitration decisions, are self-certifying. Section

293.16 addresses the Secretary's discretionary authority to disapprove a compact or amendment.

Some commenters also noted that a Tribe may choose to adopt a compact or amendment, including an arbitration award, under protest and requested the Department revise § 293.8(b) to allow for a Tribe to adopt a compact or amendment under protest.

The Department declines to include the requested revision. Section 293.8(b) requires a Tribal resolution or other document that certifies that the Tribe has approved the compact or amendment in accordance with applicable Tribal law. The Department notes that a Tribal resolution or cover letter may articulate that the Tribe's 'approval' is under protest or identify provisions in the compact or amendment that the Tribe disagrees with or is concerned violate IGRA.

One commenter questioned the Department's proposed change of pronoun in § 293.8(c) from ''he or she'' to ''they.''

The Department made certain stylistic edits including using a gender-neutral pronoun in § 293.8(c), which is the only section that uses a pronoun.

Several commenters expressed support for the proposed revisions to § 293.8. Commenters noted that the proposed § 293.8(d) reflects proposed changes to §§ 293.4, 293.21, and 293.27, which address certain types of ancillary documents which are sometimes referenced or required by a compact or amendment.

The Department acknowledges the comments.

Several commenters expressed concern with § 293.8(d) and questioned if the documents required by § 293.8 were subject to secretarial review and approval. Commenters noted that the Consultation Draft of § 293.4 expanded the Department's definition of compacts or amendments subject to Secretarial review and appeared to conflict with § 293.8(d). Commenters further noted §§ 293.4 and 293.8(d) could capture Tribal Gaming ordinances and/or minimum internal control standards which may not be drafted at the time of compact submission. Commenters noted a broad reading of § 293.8(d) posed an undue burden on Tribes and impermissibly intruded into Tribal self-governance and self-determination.

The Department has revised § 293.8(d) to clarify this provision does not apply to Tribal Gaming Ordinances subject to review and approval by the Nation Indian Gaming Commission pursuant to 25 U.S.C. 2710 and 25 CFR part 522. Further, the Department has revised § 293.4 to clarify which documents are compact or amendments subject to Secretarial review. The documents identified in § 293.8(d) allow the Department to understand how the compact or amendment interacts with other documents and agreements, which in some instances are treated as grounds for material breach of the compact. The Department notes in some instances compacts have utilized ancillary documents to improperly impose State law or State law equivalent onto Tribal governments and a Tribe's Indian lands.

Several commenters requested the Department revise § 293.8(d) by including the phrase ''provided however that nothing herein shall prohibit the amendment, modification, or other changes to Tribal ordinance or laws and any such change, amendment, or modification is not required to be submitted for review and approval unless otherwise expressly required by Federal law.''

Several commenters requested the Department amend proposed § 293.8(d) to state that any agreement between a Tribe and a State, its agencies or its political subdivisions required by a compact or amendment if the agreement requires the Tribe to make payments to the State, its agencies, or its political subdivisions, or it restricts or regulates a Tribe's use and enjoyment of its Indian Lands. Commenters argued this language is more narrowly tailored and addresses the concerns raised in § 293.28 of the Consultation Draft. Commenters requested the Department defer to a Tribe's decision to provide voluntary payments to local governments as permitted by IGRA at 25 U.S.C. 2710(b)(2)(B)(v).

One commenter suggested comprehensive revisions to Section 293.8, including renumbering the subsections and adding two new sections. The commenter proposed adding references to amendments arising out of dispute resolution processes including arbitration. The commenter proposed adding a new section addressing the Secretary's authority to waive the requirements of § 293.8. The commenter also proposed adding a section requiring the Secretary to provide notice to the parties within 14 business days if the Secretary determines documents required by § 293.8 are missing and permit the parties to either submit the documents or request a waiver of § 293.8.

The Department declines to include the requested new provisions in § 293.8. The Department notes that the requested provision addressing the Secretary's authority to offer a wavier under 25 CFR 1.2 is not required for the Secretary to issue a waiver of specific requirements. The Department also notes that the requested provision addressing a notice to the parties providing an opportunity to cure deficiencies reflects the Department's longstanding practice. Additionally, the remaining language in that provision addresses the Secretary's authority to disapprove a compact or amendment and is addressed in § 293.16.

Several commenters expressed concerns with § 293.8(e), arguing the section is vague and ambiguous, potentially permitting the Department to request documents unrelated to the Secretary's review of the submitted compact.

The Department notes § 293.8(e) in the Consultation Draft retains the text of § 293.8(d) in the 2008 Regulations. This provision allows the Department to request additional information—when needed—to determine if a submitted compact complies with IGRA.

Comments on § 293.9 Where should a compact or amendment be submitted for review and approval?

A number of commenters responded to the Department's seventh consultation question ''[s]hould the draft revisions include provisions that offer or require the submission of electronic records?'' Commenters encouraged the Department to include provisions allowing electronic submission but cautioned against requiring electronic submission. Commenters noted electronic submission is less expensive and is faster than traditional methods of submission. Commenters also noted parties should be provided reasonable flexibility when submitting compacts or amendments for Secretarial Review. Several commenters questioned the need for the inclusion of electronic submission in the proposed regulations, noting in their experience the technical requirements of submission are not a significant consideration between parties negotiating a compact.

The Department acknowledges the comments and has included the Office of Indian Gaming's email address in § 293.9. The Department notes the Consultation Draft included proposed revisions to the 2008 Regulations which were stylistic or technical in nature including electronic submission.

Several commenters requested the Department revise § 293.9 by removing the requirement for hard copy submission of the ''original copy'' when a party chooses to utilize email submission. Commenters noted that the Department could request an original hard copy if needed under § 293.8(e). Commenters also noted many Tribal and

State governments as well as the gaming industry are utilizing electronically signed and verified documents.

The Department will reevaluate the requirements in § 293.8(a) for an ''original compact or amendment executed by both the Tribe and the State'' and § 293.9 ''as long as the original copy is submitted to the address listed above'' as the Department updates the record keeping requirements. The Office of Indian Gaming is the formal record keeper and archivist of Tribal-State gaming compacts for the Department. The Office is bound by Departmental record keeping requirements, including electronic records.

Comments on § 293.10 How long will the Secretary take to review a compact or amendment?

Several commenters expressed support for the proposed revisions to § 293.10.

The Department acknowledges the comments.

Comments on § 293.11 When will the 45-day timeline begin?

Several commenters recommended the Department amend § 293.11 to allow for electronic submissions to trigger the 45-day review period upon submission by removing the requirement for the Office of Indian Gaming to stamp the document received. Commenters argued that the inclusion of a date stamp for electronically submitted documents is no longer necessary to confirm when the document was received. Commenters also noted the requirement for the Office of Indian Gaming to date stamp a document received could result in administrative delays.

The Department declines to remove the requirement for the Office of Indian Gaming to stamp the document received in order for the 45-day review period to begin for electronically submitted documents. The Department notes the Consultation Draft of § 293.11 reflects the removal of the cross reference to § 293.9 and the address of the Office of Indian Gaming. The consultation draft of § 293.9 was amended to include a dedicated email address for the Office of Indian Gaming to facilitate email submission of documents. The application of a date stamp for submitted documents irrespective of the submission method allows for consistent timely processing of all documents.

Several commenters requested the Department amend § 293.11 to include a requirement that the Office of Indian Gaming provide submitters with an email acknowledgement of receipt with confirmation of the 45-day review period.

The Department has revised § 293.11 to include an emailed acknowledgement of receipt to the parties when the parties have provided their email addresses.

Several commenters noted an apparent conflict between §§ 293.11 and 293.9 and requested clarification if the 45-day review period begins with the receipt of the electronic copy or upon receipt of the mailed original copy.

The Consultation Draft reflected revisions in §§ 293.9 and 293.11 to allow for electronic or hard copy submission. The Department has revised § 293.9 to clarify the Department will accept either email or hard copy submission but requires a hard copy submission in addition to the emailed copy. The 45-day review period starts when the Office of Indian Gaming date stamps a hard copy original or an electronic copy of the document.

Comments on § 293.12 What happens if the Secretary does not act on the compact or amendment within the 45-day review period?

Several commenters noted that it was unclear what the legal effect is for a compact or amendment ''approved by operation of law'' or ''deemed approved'' when a guidance letter is issued after the 45-day review period.

The Department acknowledges the comments. A guidance letter issued after the 45th day review period does not alter the effective date of the compact or amendment. The effective date of a compact or amendment is the date the document is published in the **Federal Register**, as explained in § 293.14. A compact or amendment approved by operation of law is considered to have been approved by the Secretary, but only to the extent the compact or amendment is consistent with the provisions of IGRA. A guidance letter explains the provisions the Department believes to be inconsistent with IGRA.

Many commenters noted that the added language effectively codifies the Secretary's current practice.

The Department acknowledges the comments.

One commenter indicated that the provision conflicts with the Secretarial requirements under § 293.10.

The Department disagrees with the comment. The proposed regulations at § 293.12 explain what happens if the Secretary does not act on the compact or amendment within the 45-day review period.

Several commenters stated that it was unclear if there would be a process to appeal a guidance letter issued after the 45-day review period, with one commenter suggesting that the Secretary should consider including an appeal or review process.

The Department acknowledges the comments but declines to amend the provision to include an appeal or review process.

One commenter stated that it was unclear from the provision if the Secretary's issuance of a guidance letter under this provision would impact the publication of a ''deemed approved'' compact in the **Federal Register**.

The Secretary's issuance of a guidance letter under this provision does not impact the publication of a ''deemed approved'' compact in the **Federal Register**. A guidance letter issued after the 45-day review period does not alter the effective date of the compact or amendment. The effective date of a compact or amendment is the date the notice is published in the **Federal Register**, as explained in § 293.14.

Several commenters expressed concern that the Secretary could ''unapprove'' a compact or amendment through issuance of a guidance letter. These commenters requested that the Department specifically address the effect of a guidance letter on a compact's approval and which provisions are not deemed approved. One commenter expressed concern that if the Secretary takes no action or issues a guidance letter, a court may interpret the Secretary's guidance letter or inaction to mean that the compact violates IGRA and is void, potentially leaving a Tribe without the authority to continue to offer gaming under the compact. One commenter based its concern on the relationship between §§ 293.12 and 293.15.

The Department acknowledges the comments. Under IGRA, the Department has 45 days to complete its review and either approve or disapprove a class III gaming compact. If the Department takes no action within that 45-day period, the Tribal-State gaming compact is considered approved by operation of law—to the extent that it is consistent with IGRA. A guidance letter issued after the 45th day of the review period does not alter the effective date of the compact or amendment. The effective date of a compact or amendment is the date the notice is published in the **Federal Register**, as explained in § 293.14. A compact or amendment approved by operation of law is considered to have been approved by the Secretary, but only to the extent the compact or amendment is consistent with the provisions of IGRA. A guidance letter explains the provisions the

Department believes to be inconsistent with IGRA.

One commenter disagreed with the inclusion of § 293.12 and stated that the Secretary should not issue guidance letters after the 45-day review period because the Secretary should only act within the 45-day review period and not beyond.

The Department disagrees with the comment. A compact is not ''considered to have been approved'' by operation of law also known as ''deemed approved'' until after the 45-day review period. The Department cannot issue a guidance letter until after the 45th day.

One commenter stated that the Secretary has an obligation to ensure that compacts between Tribes and States are rejected if they violate the provisions of IGRA and stated that § 293.12 appears to permit the Secretary to allow compacts that violate IGRA to be ''deemed approved'' without alerting the relevant State, Tribe, or the public that provisions of the ''approved'' compact violate IGRA. The commenter recommended that § 293.12 be amended to state that ''[t]he Secretary, after the 45th day, is required to issue a guidance letter to the parties identifying any provisions that are inconsistent with IGRA and thus not approved by operation of law.'' Another commenter suggested the Department add language stating ''Accordingly, the signatory Tribe or State may subsequently challenge the non-compliant compact provisions as unenforceable or severable from the compact.''

The Department accepts the comments in part and will make the appropriate changes to § 293.12, indicating the Secretary will issue a letter confirming the 45-day review period has lapsed and therefore the compact or amendment has been approved by operation of law. The Secretary's letter may identify provisions of the ''deemed approved'' compact that violate IGRA. The Department takes no position on whether a Tribe or a State may subsequently challenge the non-compliant compact provisions as unenforceable or severable from the compact.

One commenter recommended that the language in this section stating that ''[t]he Secretary is not required to issue a letter, and if the Secretary does issue a letter, any such letter may offer guidance to the parties on the Department's interpretation of IGRA,'' be stricken.

The Department agrees with the changes and will strike the language from § 293.12. The Secretary will issue a letter confirming the 45-day review period has lapsed and therefore the compact or amendment has been approved by operation of law.

Many commenters requested that the Department state how it will determine whether to issue a guidance letter and articulate a standard to promote the uniform issuance of guidance letters. These commenters expressed concern that if the Secretary is not required to issue a guidance letter, the lack of a guidance letter may place some Tribes on unequal footing. These commenters request that § 293.12 be revised to articulate a standard that will ensure the uniform issuance of guidance letters.

The Department accepts the comments in part and will make the appropriate changes to § 293.12, indicating the Secretary will issue a letter confirming the 45-day review period has lapsed and therefore the compact or amendment has been approved by operation of law. The Secretary's letter may include guidance identifying provisions of the ''deemed approved'' compact that violate IGRA.

One commenter recommended that the Department clarify whether revised § 293.12 is intended to be a change in Department policy or a drafting error.

The Department acknowledges the comment. Section 293.12 will reflect a change in policy to issue a letter in each instance when a compact is deemed approved and clarify that letter may include guidance identifying provisions of the ''deemed approved'' compact that violate IGRA.

Several commenters requested the inclusion of a deadline by which the Secretary will issue a guidance letter. One commenter requested that § 293.12 be revised to provide that guidance letters be issued within 60 days of the date a compact is approved by operation of law in order to provide Tribes with certainty with respect to renegotiating terms of a compact and avoid lost time negotiating provisions the Department finds are in conflict with IGRA.

The Department accepts the comments in part. Section 293.12 will reflect that the Secretary will issue a letter after the 45th day but within 90 days from the date of submission. This timeline is consistent with the requirement to publish notice in the **Federal Register** in § 293.14.

Several commenters expressed concerns that the Secretary has no explicit statutory authority to issue a guidance letter. One commenter expressed concerns that a guidance letter, which is not required to be issued under IGRA, could be used as a litigation roadmap, potentially to oppose the project, and may pin the Secretary to a litigation position. The commenter suggested further discussion and requested that the Secretary consider a process that would provide confidentiality to the Tribe and State by, for example, communicating to the attorneys for the respective Tribe and State the Secretary's concerns if any provisions were inconsistent with IGRA to discuss perceived inconsistencies.

The Department acknowledges the comment. The Secretary has authority to promulgate these regulations based on the statutory delegation of powers contained in IGRA and 25 U.S.C. 2, and 9 to review compacts and amendments. A guidance letter issued after the 45th day review period does not alter the effective date of the compact or amendment. A compact or amendment approved by operation of law is considered to have been approved by the Secretary, but only to the extent the compact or amendment is consistent with the provisions of IGRA. A guidance letter explains the provisions the Department believes to be inconsistent with IGRA. The Department currently offers technical assistance to Tribes and States; however the Department does not provide pre-approvals or legal opinions.

One commenter noted that ''deemed approval'' letters have had the effect of allowing States like California to attempt to use the letter as a way of forcing impermissible provisions into compacts.

The Department accepts the comments in part and will make the appropriate changes to § 293.12, indicating the Secretary will issue a letter informing the parties that the compact or amendment has been approved by operation of law, the letter may identify provisions of the ''deemed approved'' compact that violate IGRA.

One commenter recommended that the revised regulations be modified to expressly state the principles underlying the policy of issuing ''deemed approved'' letters and the limits of that policy.

The Department accepts the comments in part and will make the appropriate changes to § 293.12, indicating the Secretary will issue a letter informing the parties that the compact or amendment has been approved by operation of law. The letter may identify provisions of the ''deemed approved'' compact that violate IGRA. The Department declines to expressly state when the letter will include guidance or limits to that policy.

One commenter noted that States are often dismissive of ''deemed approved'' letters and requested that the Department revise the language to state that ''[a]ccordingly, the signatory Tribe or State may subsequently challenge the non-compliant compact provisions as unenforceable or severable from the compact,'' stating that this additional language would eliminate State's false perception that an approval by operation of law is de facto approval of a State's ''illicit agenda in compact negotiations.''

The Department acknowledges the comment. Under IGRA, the Department has 45 days to complete its review and either approve or disapprove a class III gaming compact. If the Department takes no action within that 45-day period, the Tribal-State gaming compact is considered approved by operation of law—to the extent that it is consistent with IGRA. The Department takes no position on whether a Tribe or a State may subsequently challenge the non-compliant compact provisions as unenforceable or severable from the compact.

Several commenters recommended that § 293.12 be amended to allow Tribal governments to request guidance letters and legal opinions from the Secretary or the Office of Solicitor for compacts.

The Department acknowledges the comment. The Department currently offers technical assistance to Tribes and States; however the Department does not provide pre-approvals or legal opinions.

One commenter stated that the issuance of a guidance letter explaining why a submitted compact was not affirmatively approved but ''deemed approved'' by operation of law was a solid improvement, noting that such letters provide an excellent source to inform and improve the negotiation process.

The Department acknowledges the comment.

Comments on § 293.13 Who can withdraw a compact or amendment after it has been received by the Secretary?

Several commenters requested the Department revise § 293.13 by adding the word ''both'' so that the relevant provision reads ''Tribe and State must both submit.''

The Department accepts the requested revision. The Department notes the parties may submit a joint request for withdrawal of the compact or amendment, or submit individual requests for withdrawal.

One commenter recommended the Department accept electronically submitted requests for withdrawal.

The Department accepts the requested revision and has revised § 293.9 to clarify all submissions and requests under part 293 must be submitted to the Office of Indian Gaming, either at the physical address or the email address.

One commenter requested the Department revise § 293.9 to permit a Tribe to unilaterally withdraw a compact or amendment after submission.

The Department declines the requested change and notes this requirement remains unchanged from the 2008 Regulations, which requires both parties to request withdrawal. The compact process under IGRA is a formalized contract between sovereigns which is submitted to the Department for review and approval only after it is legally entered into or is otherwise binding on the parties.

Comments on § 293.14 When does a compact or amendment take effect?

Several commenters requested clarity of the effect of an approval by operation of law on a compact and subsequent publication of a notice in the **Federal Register**.

The Department acknowledges the comments. The Department notes IGRA provides a 45-day review period after which a compact is approved by operation of law but only to the extent the compact is consistent with IGRA. 25 U.S.C. 2710(d)(8)(C). A notice must also be published in the **Federal Register** for the compact to be in effect. 25 U.S.C. 2710(d)(8)(D).

One commenter requested the Department amend § 293.14 by changing the timeline for publication of a notice in the **Federal Register** from 90 days to 55 days from the date the compact or amendment is received to, or within 10 days of approval/disapproval, whichever is shorter.

The Department declines the requested change in the **Federal Register** notice timeline, which remains unchanged from the 2008 Regulations and is considered reasonable. The Department notes IGRA does not require publication of a notice in the **Federal Register** if the compact or amendment is disapproved.

Comment on § 293.15 Is the Secretary required to disapprove a compact or amendment that violates IGRA?

Several commenters agreed with the Department's proposed language in § 293.15, explaining that the Secretary has the discretionary authority to disapprove a compact that violates IGRA, but is not required to do so. However, many of the commenters that agreed with the Department's proposed language did express concern over the possibility that the language could encourage future administrations to avoid disapproving compacts where appropriate. Other commenters noted the importance of Deemed Approval determinations to empower Tribes to reject the non-compliant provisions of a deemed approved compact through litigation or other means.

The Department acknowledges the comments. The Department retains its proposed language in § 293.15. The Department is concerned a mandate that the Secretary affirmatively disapprove compacts that violate IGRA would narrow the discretion IGRA provides to the Secretary to either disapprove or approve a compact within a 45-day review period. Furthermore, this type of mandate could create unintended consequences if the Department fails to act within the prescribed 45-day review period on a compact that violates IGRA. The current language, which tracks the language of IGRA, provides that if the Secretary fails to act within the 45-day review period, the compact is deemed approved but only to the extent it is consistent with IGRA.

Several commenters expressed concern with the Department's proposed language in § 293.15 and argued that a compact which violates IGRA must be affirmatively disapproved. Another commenter went as far as stating that allowing compacts to go into effect that should be disapproved is a violation of IGRA.

The Department acknowledges the comments. The Department retains its proposed language in § 293.15. The Department is concerned a mandate that the Secretary affirmatively disapprove compacts that violate IGRA would narrow the discretion IGRA provides the Secretary to either approve or disapprove a compact within the prescribed 45-day review period. Furthermore, this type of mandate could create unintended consequences if the Department fails to act within the prescribed 45-day review period on a compact that violates IGRA. The current language, which tracks the language of IGRA, provides that if the Secretary fails to act within the 45-day time period, the compact is deemed approved but only to the extent it is consistent with IGRA.

Finally, a few commenters agreed that the Secretary has discretionary authority over whether to disapprove a compact but should be required to issue a guidance letter or legal opinion identifying provisions not approved under IGRA. Commenters recommended the Secretary defer to a Tribe's sovereign decision-making and permit compacts to go into effect rather than disapprove.

The Department acknowledges the comments. The Department retains its proposed language in § 293.15. The Department is concerned a mandate that the Secretary affirmatively disapprove compacts that violate IGRA would narrow the discretion IGRA provides the Secretary to either approve or disapprove a compact within the prescribed 45-day review period. Furthermore, this type of mandate could create unintended consequences if the Department fails to act within the prescribed 45-day time period on a compact that violates IGRA. The current language, which tracks the language of IGRA, provides that if the Secretary fails to act within the 45-day time period, the compact is deemed approved but only to the extent it is consistent with IGRA. The Department has revised § 293.12 to provide the Secretary will issue a letter informing the parties that the compact or amendment has been approved by operation of law and the letter may include guidance.

Comments on § 293.16 When may the Secretary disapprove a compact or amendment?

Several commenters requested the Department clarify § 293.16(a)(3) and suggested the provision is overly broad.

The Department acknowledges the comments, but notes this provision is consistent with Congress's grant of discretionary disapproval authority to the Secretary. 25 U.S.C. 2710(d)(8)(B)(iii).

Several commenters recommended the Department revise § 293.16(a)(3) to include an opportunity for an appropriate designee of the Secretary to serve as a mediator to facilitate fair compact negotiations between a Tribe and a State and to ensure that Federal law is complied with by the parties.

The Department acknowledges the comments. The Department routinely provides technical assistance to Tribes and States including guidance on Departmental precedents and past procedures, the Departments interpretation and application of case law, as well as best practices.

One commenter requested the Department include a new section titled ''[m]ay a compact or amendment include provisions that violate the trust obligations of the United States to Indians?'' The proposed text for this section would explain that a compact may not include provisions that violate the trust obligations of the United States and cited to provisions limiting third-party Tribe's rights to conduct gaming as an example of a provision violating the trust obligation.

The Department declines the requested new section and notes § 293.24(c)(1) addresses compact provisions which act to limit a third-party Tribe's rights to conduct gaming.

Several commenters expressed support for the proposed § 293.16(b) and noted it helps enforce the requirements in other sections of part 293.

The Department acknowledges the comments.

Several commenters objected to the proposed § 293.16(b) which provides the Secretary may disapprove a compact if the documents required in § 293.8 are not submitted. Commenters questioned the Secretary's authority to disapprove a compact based on the parties' failure to submit specific documents. Several commenters expressed concerns that the document required by § 293.8(d) may be overly broad and burdensome. Other commenters recommended the Department revise § 293.16 to require written notice of deficiencies and an opportunity to cure before disapproving a compact under § 293.16(b).

The Department accepts the comments and notes § 293.16(b) provides the Secretary with grounds to disapprove a compact if the documents required by § 293.8 are not submitted. The Department has revised § 293.16(b) to require written notice of deficiencies, which is consistent with the Department's longstanding practice of informing parties of deficiencies and permitting parties to cure the deficiencies. IGRA provides the Secretary with discretionary authority to disapprove a compact if it violates one of the three specified criteria. 25 U.S.C. 2710(d)(8)(B). Section 293.16(b) allows a presumption that a compact violates one of the three specified criteria if the parties fail to cure deficiencies in the record.

Several commenters requested the Department revise § 293.16(b) to provide if the parties fail to submit the required documents in § 293.8, the Secretary will return the compact as incomplete. The commenters recommended the Department clarify that the parties may resubmit the compact or amendment after it has been returned based on the failure to submit the required documents, but must submit all of the required supporting documents.

The Department declines to accept the requested provisions. IGRA provides the Secretary with 45-days to review and approve or disapprove a compact. The Secretary does not have the authority to return a compact as incomplete which could frustrate Congress's clear intent to prevent unnecessary delay by providing a 45-day review period.

One commenter recommended the Department revise § 293.16 by including a provision permitting the Secretary while reviewing an amendment to a compact to disapprove provisions in the underlying compact or amendment which was approved by operation of law if that provision violates one of IGRA's three specified criteria.

The Department declines to include the proposed provision. IGRA limits the Secretary's authority to review and approve or disapprove a compact or amendment to 45 days. As a result, the Department cannot retroactively approve or disapprove a compact or amendment after the 45-day review period has run. Instead, the Department's review is limited to the text of the document under review during the 45-day review period. The Department treats restated and resubmitted compacts as a new compact because the parties have submitted entire text of the compact for review. The Department encourages parties to utilize restated compacts or amended and restated compacts as a best practice to incorporate a series of amendments into a single document. The Department finds it helpful if the Tribe or State also submits a redlined copy of the restated compact.

Comments on § 293.17 May a compact or amendment include provisions addressing the application of the Tribe's or the State's criminal and civil laws and regulations?

Several commenters expressed support for the proposed § 293.17.

The Department acknowledges the comments.

Several commenters recommended the Department revise § 293.17 to clarify how the parties can comply with the requirement to ''show that these laws and regulations are both directly related to and necessary for, the licensing and regulation of the gaming activity.'' Commenters noted this provision adds a vague new requirement that could cause confusion.

The Department accepts this comment in part. The Department has revised § 293.17, to clarify the Secretary may ask for a showing that the provisions addressing the application of criminal and civil laws and regulations are both directly related to and necessary for, the licensing and regulation of the gaming activity.

Several commenters addressed § 293.17 in responding to the Department's third consultation question ''[s]hould the draft revisions include provisions that facilitate or prohibit the enforcement of State court orders related to employee wage garnishment or patron winnings?'' Commenters suggested the parties may address the effect of such State (or Tribal) court orders as a jurisdictional matter under § 293.17.

The Department declines to address the enforcement of State court orders related to employee wage garnishment or patron winnings in § 293.17. The Department has added enforcement of State court orders to the list of provisions in a compact which are not directly related to the operational gaming activities in § 293.24(c). The Department notes this is consistent with the 9th Circuit decision in *Chicken Ranch Ranchera of Me-Wuk Indians* v. *California,* 42 F.4th 1024 (9th Cir. 2022).

Comments on § 293.18 May a compact or amendment include provisions addressing the allocation of criminal and civil jurisdiction between the State and the Tribe?

A number of commenters responded to the Department's fourth consultation question: ''[s]hould the draft revisions include provisions that facilitate or prohibit State court jurisdiction over the gaming facility or gaming operations? Should this apply to all claims or only certain types of claims?''

Many commenters discouraged the Department from including provisions which could be perceived as permitting or facilitating State court jurisdiction because States have a history of leveraging limited grants of jurisdiction to undermine Tribal sovereignty. Commenters noted while IGRA includes allocation of jurisdiction it also is intended to promote strong Tribal governments which includes strong Tribal courts. Other commenters noted Tribal courts should be the default jurisdiction, however court jurisdiction could be left to negotiations between a Tribe and State, at the request of a Tribe when the Tribal court does not have the capability to take full jurisdiction over the relevant claims. Commenters also discussed case law supporting the presumption that Tribal court is the proper venue for third party claims—including patron disputes, labor disputes, and tort claims against the Tribe arising out of the Tribe's gaming facility.

The Department acknowledges the comments. The Department proposed § 293.18 to clarify the Department reads IGRA's provision permitting Tribes and States to allocate criminal and civil jurisdiction narrowly and limited by § 293.17. The Department has addressed third party tort claims in proposed § 293.24(c).

Several commenters supported the proposed § 293.18, as drafted, and noted it appears consistent with IGRA and case law. Commenters also noted the proposed provision could help preserve Tribal court systems.

The Department acknowledges the comments.

Several commenters questioned the need for the proposed § 293.18.

The Department acknowledges the comments. The Department notes IGRA provides a compact may include provisions relating to the allocation of criminal and civil jurisdiction between the State and the Tribe necessary for the enforcement of such laws and regulations. 25 U.S.C. 2710(d)(3)(C)(ii).

Several commenters requested the Department include a bad faith standard for jurisdiction when a State seeks to compel State jurisdiction of the Tribe or Indian country.

The Department acknowledges the comments. The Department has added provisions in § 293.24(c) to address these concerns, which § 294.24(d) now states are ''considered evidence of a violation of IGRA.''

Several commenters requested the Department amend proposed § 293.18 to expressly require the Tribe to request the State take jurisdiction over claims involving the gaming facility or gaming operations in order for such an allocation of jurisdiction to be proper.

The Department did not adopt the comment. A compact or amendment may include provisions allocating criminal and civil jurisdiction between the State and the Tribe necessary for the enforcement of the laws and regulations described in § 293.17.

Several commenters requested the Department revise § 293.18 to prohibit State court jurisdiction over Tribal gaming operations or facilities.

The Department did not adopt the comment. A compact or amendment may include provisions allocating criminal and civil jurisdiction between the State and the Tribe necessary for the enforcement of the laws and regulations described in § 293.17.

Comments on § 293.19 May a compact or amendment include provisions addressing the State's costs for regulating gaming activities?

A number of commenters expressed support for the proposed § 293.19. Commenters noted States have used IGRA's regulatory cost provision as an indirect tax often funding both regulatory and non-regulatory functions. Commenters opined the bad faith standard would assist negotiating parties in limiting regulatory cost provisions and Tribal oversite over the State's use of those funds. Commenters also noted the Department will likely receive severe pushback from States on this provision and encouraged the Department to ''stay the course.''

The Department acknowledges the comments. Section 293.19 addresses Tribal payments for the State's costs of regulating gaming activities. As explained above the Department has replaced the phrase ''evidence of bad faith'' with ''evidence of a violation of IGRA.''

Several commenters expressed concern with the inclusion of a bad faith standard in proposed § 293.19. Commenters questioned the Secretary's authority to determine bad faith and questioned how the Department would enforce such a provision over the life of the compact.

IGRA provides the Secretary with the authority to review and approve or disapprove a compact within a 45-day review period. The Department evaluates the terms of the compact including auditing standards for assessments of regulatory costs as part of this review. The Department has revised § 293.19 to clarify the Secretary's review is limited to the terms of the compact. Enforcement of those terms lies with the parties and is governed by the compact's dispute resolution provisions, if any. As explained above, the Department has replaced the phrase ''evidence of bad faith'' with ''evidence of a violation of IGRA.''

Several commenters requested the Department provide definitions for ''actual and reasonable'' and provide boundaries on the types of costs for which the State may reasonably seek reimbursement. Other commenters requested the Department allow flexibility for States to aggregate costs with limits on what costs can be aggregated.

The Department declines to provide specific boundaries on the types of gaming regulatory costs for which the State may seek reimbursement. The Department reads IGRA's provision permitting the State to assess regulatory costs narrowly and inherently limited to the negotiated allocation of regulatory jurisdiction. Providing specific definitions would diminish parties' flexibility in negotiating a reasonable allocation of regulatory jurisdiction that best meets the needs of the parties. Further, the Department has revised § 293.19 to give parties the flexibility in negotiating the terms of a compact to determine how the State will show aggregate costs are actual and reasonable.

Several commenters requested the Department require the State to provide annual audits, prove actual and reasonable expenses, and periodically negotiate regulatory costs. One commenter requested the Department add the phrase ''and reasonable'' to the last sentence in § 293.19. Another commenter requested the Department add the phrase ''or refuses to provide such records'' to the last sentence in § 293.19.

The Department has accepted these suggested edits in part and has revised § 293.19, to reflect these comments.

Several commenters requested the Department clarify how the department distinguishes between assessed regulatory costs and a prohibited tax, fee, charge, or other assessment.

The Department acknowledges the comments. Section 293.25 includes a discussion of the Department's interpretation of IGRA's prohibition against the imposition of a tax, fee, charge, or other assessment. IGRA provides a compact may include provisions relating to ''the assessment by the State of [the Tribe's class III gaming activity] in such amounts as are necessary to defray the costs of regulating [the Tribe's class III gaming activity].'' 25 U.S.C. 2710(d)(3)(C)(iii). IGRA in section 2710(d)(4) then prohibits the State from imposing a tax, fee, charge, or other assessment except for any assessments that may be agreed to under paragraph (3)(C)(iii). The Department reads IGRA's provision permitting the State to assess regulatory costs narrowly and inherently limited to the negotiated allocation of regulatory jurisdiction. Section 293.25 includes a discussion of the Department's interpretation of IGRA's prohibition against the imposition of a tax, fee, charge, or other assessment.

Comments on § 293.20 May a compact or amendment include provisions addressing the Tribe's taxation of gaming?

Several commenters expressed support for the proposed § 293.20, and noted clear guidelines are beneficial to all parties by reducing the risk that improper provisions will be included. Commenters expressed support for the inclusion of a bad faith standard in the proposed § 293.20. Several commenters requested the Department add the word ''presumptive'' so the relevant sentence would read ''[t]he inclusion of provisions addressing the Tribe's taxation of other activities is considered presumptive evidence of bad faith.''

The Department acknowledges the comments but declines to add the word ''presumptive.'' As explained above the Department has replaced the phrase ''evidence of bad faith'' with ''evidence of a violation of IGRA.''

Several commenters expressed opposition for the proposed § 293.20. Commenters raised concerns that the proposed text appears to allow States to tax gaming revenue. Other commenters noted this may cause States to demand specific forms of Tribal taxation of Tribal gaming and argues the provision is unnecessary.

The Department acknowledges the comment, but notes IGRA provides a compact may address Tribal taxation of Tribal gaming in amounts comparable to State taxation of State gaming. 25 U.S.C. 2710(d)(3)(C)(iv). The Department has revised § 293.20 to clarify this provision.

Comments on § 293.21 May a compact or amendment include provisions addressing remedies for breach of the compact?

Several commenters expressed support for the proposed § 293.21 and the inclusion of a bad faith standard. Several commenters discussed their experiences with States seeking to enforce dispute resolution agreements or decisions that violated IGRA.

The Department acknowledges the comments. As explained above, the Department has replaced the phrase ''evidence of bad faith'' with ''evidence of a violation of IGRA.''

Several commenters questioned the Secretary's authority to review dispute resolution agreements, arbitration awards, settlement agreements, or other resolutions of a dispute outside of Federal court.

The Department acknowledges the comments. The Secretary has authority to promulgate these regulations based on the statutory delegation of powers contained in IGRA and 25 U.S.C. 2, and 9 to review compacts and amendments. The Department is aware of arbitration awards, settlement agreements, and other similar dispute resolution agreements which have amended the terms of a compact. IGRA requires the Secretary to review compacts and publish notice in the **Federal Register** before a compact is in effect and the Department has made conforming edits to § 293.4.

Several commenters expressed concern with the proposed § 293.21. Commenters stated the documents sought under the provision was overly broad. Other commenters suggested the proposed § 293.21 would encourage parties to seek dispute resolution in Federal court and discourage parties from seeking more cost effective and faster resolution of disputes because of the risk the Secretary may reject the agreement. Commenters noted settlement agreements are often confidential. One commenter requested clarification why the Department is interested in reviewing dispute resolution agreements and arbitration awards. Another commenter cautioned the Department's review of these provisions may prevent Tribes from exercising self-determination and sovereignty in compact negotiations.

The Department acknowledges the comments. The Department seeks to ensure all compacts, amendments, and dispute resolution agreements or awards are consistent with IGRA and are properly in effect. The Department has made conforming edits to §§ 293.2, 293.4, 293.7, and 293.21 to address concerns raised regarding secretarial review of compact amendments arising out of dispute resolution. The Department encourages parties to resolve compact disputes in a timely, cost-effective manner, which is consistent with IGRA.

Several commenters requested the Department revise the proposed § 293.21 by amending the title and adding text to § 293.21. The proposed title would read: ''[m]ay a compact or amendment include provisions addressing the resolution of disputes for breach of the compact?''

The Department has accepted the proposed revisions in part. As explained above, the Department has replaced the phrase ''evidence of bad faith'' with ''evidence of a violation of IGRA.''

Several commenters requested the Department clarify if compacts should include dispute resolution options other than termination of a compact, which only harms the Tribe.

The Department acknowledges the comments. The Department notes that compacts are carefully negotiated long-term agreements between sovereigns. IGRA provides compacts may include ''remedies for breach of contract.'' The Department notes well drafted compacts include options for the parties to continue operating under the compact, while seeking to resolve any disputes arising from the compact. If the compact includes payments to the State for regulatory costs as described in proposed § 293.19, or revenue sharing as described in § 293.25, the Department recommends including provisions which permit the Tribe to divert disputed funds into an escrow account.

One commenter requested the Department include a grandfather clause for established settlement agreements to protect the settled expectations of parties to existing agreements. The commenter explained a party may seek to relitigate a settled dispute by arguing the agreement is not valid.

The Department declines to include a grandfather clause for settlement agreements which have not been submitted for Secretarial review and publication of a notice in the **Federal Register**. The Department has included revisions to the proposed § 293.21 as well as § 293.4 to clarify and limit the scope of this review. The Department encourages parties to seek § 293.4 review if the parties are concerned their settlement agreement is an 'amendment.'

Comments on § 293.22 May a compact or amendment include provisions addressing standards for the operation of gaming activity and maintenance of the gaming facility?

A number of commenters expressed support for the proposed § 293.22 and requested the Department strengthen the provision by defining what qualifies as ''maintenance'' in greater detail. Commenters explained some States seek expansive regulatory standards that are not related to the maintenance of a facility. Other commenters noted State's may seek to require a Tribe to adopt State law equivalent ordinances and requested the Department add the following sentence to § 293.22, ''[i] f a compact or amendment mandates that the Tribe adopt standards equivalent or comparable to the standards set forth in a State law or regulation, the parties must show that these mandated Tribal standards are both directly related to and necessary for, the licensing and regulation of the gaming activity.''

The Department acknowledges the comments and has revised § 293.22 by including the requested sentence.

Comments on § 293.23—Which Has Been Renumbered as 293.24—What factors will be used to determine whether provisions in a compact or amendment are directly related to the operation of gaming activities?

The Department has renumbered the proposed § 293.23 as § 293.24 comments have been edited to reflect the new section number.

Several commenters expressed support for the proposed § 293.24. Commenters explained the provision would improve compact negotiations by providing parties with clear guidance on which topics are consistent with IGRA and which topics are outside of IGRA's narrow scope of compact terms under 25 U.S.C. 2710(d)(3)(C). Commenters noted the proposed § 293.24 is consistent with the Departments long standing requirement of a direct connection and repudiation of some States' application of a ''but for'' test.

The Department acknowledges the comments.

One commenter expressed concern that the Department was inadvertently creating additional tests including a ''incidental benefit'' test in § 293.24.(b) and a ''not directly related'' test in § 293.24(b) and (c) as well as an ''unrelated to'' test in § 293.24(c)(4).

The Department acknowledges the comments. The Department has revised § 293.24(b) and (c)(4) for consistency and notes the phrase ''not directly related'' as used in § 293.24 as the inverse of the phrase ''directly related.''

One commenter recommended the Department include a section immediately preceding proposed § 293.24 mirroring the question-and-answer format of the proceeding sections in Subpart D. The section would be titled ''[m]ay a compact or amendment include provisions that are not directly related to the operation of gaming activities?'' With a firm declaration that provisions which are not directly related to the operation of gaming activities is a violation of IGRA.

The Department has incorporated the recommended section with modifications for consistency with the proceeding section in Subpart D. The new section is numbered § 293.23 and the following sections have been renumbered.

Several commenters recommended the Department revise § 293.24 by inserting the word ''activity'' or ''activities'' after the phrase ''class III gaming'' for consistency with other sections in part 293.

The Department has added the word ''activity'' or ''activities'' as appropriate in § 293.24.

Several commenters requested the Department provide a table of authority for provisions considered ''directly related to the operation of gaming activities'' under § 293.24(a) as well as provisions considered ''not directly related to the operation of gaming activities'' under § 293.24(c). Commenters recommended the Department revise or remove provisions which were not supported by past decisions issued by the Department and/or case law.

The Department has prepared a table of authorities addressing these and other provisions.

Several commenters recommended the Department provide standards and/or a procedure within the regulatory text outlining how the parties are expected to comply with the requirement in § 293.24(a) to ''show that [provisions included in the compact or amendment] are directly connected to the Tribe's conduct of class III gaming.'' Commenters also recommended the Department include in the part 293 regulations deference to a reasonable Tribal determination that a provision is directly connected to the Tribe's conduct of class III gaming.

The Department declines to provide a specific procedure for complying with § 293.24 in order to provide the parties with the necessary flexibility to address the specific terms of their agreement. Some parties chose to provide a justification brief explaining key or novel provisions to the Department as part of their compact or amendment submission. When necessary, the Department's practice is to request additional information from the parties regarding specific provisions in the compact or amendment. Additionally, the Department frequently provides technical assistance to parties negotiating a compact or amendment by flagging provisions which may violate IGRA or may require additional justification. A best practice for compacts requiring State legislative approval is to seek technical assistance before the compact is formally adopted by legislative action.

A number of commenters responded to the Department's third consultation question ''[s]hould the draft revisions include provisions that facilitate or prohibit the enforcement of State court orders related to employee wage garnishment or patron winnings?'' Commenters encouraged the Department to include provisions which prohibit Tribal enforcement of State court orders related to employee wage garnishment and/or patron winnings in compacts. The commenters explained that these provisions are not directly related to operation of gaming activities under 25 U.S.C. 2710(d)(3)(C)(vii). Further some commenters explained they have prevailed in litigation arguing that State court wage garnishment orders are not binding on the Tribe or the Tribe's employees. Commenters noted that while comity agreements between sovereigns may be mutually beneficial, compact negotiations should not be used to force Tribes to enforce these provisions. Commenters also explained without a Tribal law mechanism for domesticating a State court order, enforcing such an order erodes Tribal sovereignty and exposes the Tribe and the Tribal gaming operation to unwarranted liability.

The Department has added enforcement of State court orders to the list of provisions which are not directly related to the operational gaming activities in § 293.24(c). The Department notes this is consistent with the 9th Circuit decision in *Chicken Ranch Ranchera of Me-Wuk Indians* v. *California,* 42 F.4th 1024 (9th Cir. 2022).

Several commenters requested the Department include in the § 293.24(c) list of provisions which are not directly related to the operation of gaming activities provisions which require the Tribe to negotiate memorandum of understanding or intergovernmental agreements with local governments.

The Department has added requiring memorandum of understanding or intergovernmental agreements with local governments to the list of provisions which are not directly related to the operational gaming activities in § 293.24(c). The Department notes this is consistent with the 9th Circuit decision in *Chicken Ranch Ranchera of Me-Wuk Indians* v. *California,* 42 F. 4th 1024 (9th Cir. 2022).

Several commenters requested the Department include in the § 293.24(c) list of provisions, which are not directly related to the operation of gaming activities, provisions which require the Tribe to submit to State court jurisdiction over tort claims arising from the Tribe's conduct of class III gaming activities.

The Department has added requiring State court jurisdiction over tort claims arising from the Tribe's conduct of class III gaming activities to the list of provisions which are not directly related to the operational gaming activities in § 293.24(c). The Department notes this is consistent with the District of New Mexico's decision in *Pueblo of Santa Ana* v. *Nash,* 972 F. Supp. 2d 1254 (D.N.M 2013).

Several commenters requested the Department include an additional paragraph to § 293.24 codifying the Department's practice of providing technical assistance letters to negotiating parties regarding whether a proposed compact provision is 'directly related' to the Tribe's operation of gaming activities consistent with IGRA. Commenters requested the Department further include avenues for parties to obtain assistance from the Department in seeking guidance letters or legal opinions from the National Indian Gaming Commission and the United States Department of Justice.

The Department declines to adopt a formal codification of its practice providing technical assistance to Tribes and States. The Department will continue to coordinate with the Department of Justice and the National Indian Gaming Commission regarding enforcement of IGRA.

Comments on § 293.24(a)

Several commenters objected to the Department's inclusion of provisions in § 293.24(a) addressing patron conduct within the gaming facility as ''directly related to the Tribe's conduct of gaming.'' Commenters argued the examples provided—without further clarification or supporting past precedent and or case law—may cause confusion and invite State overreach. Other commenters noted the examples provided of subjects regulating patron conduct included subjects which resulted in contentious negotiations with their respective States, including State attempts to ban alcohol and smoking in Tribal facilities while requiring State licensed facilities serve alcohol. Other commenters recommended the Department revise the list of examples in § 293.24(a) to reflect non-controversial subjects that are ''directly related to the Tribe's conduct of gaming'' including minimum age restrictions and the transportation of gaming devices and equipment.

The Department acknowledges the comments. The Department has provided a comprehensive table of authorities supporting the examples included in § 293.24(a). The Department has also revised the list to reflect non-controversial subjects the Department has found to be ''directly related to the Tribe's conduct of gaming.'' We note the inclusion of an item in the Department's ''directly related'' list in § 293.24(a) does not suggest a State may insist on any requirement addressing a ''directly related'' item.[6]

Several commenters recommended stylistic edits to § 293.24(a) for consistency with § 293.24(c).

The Department has revised § 293.24 for consistency.

One commenter noted the reference to patron conduct in § 293.24(a) could include illegal patron conduct including trafficking in the gaming facility and adjacent non-gaming amenities. The commenter requested the Department's view on provisions which address criminal jurisdiction.

The Department acknowledges the comment. The phrase ''patron conduct'' has been removed from § 293.24(a). Further, criminal jurisdiction is addressed in § 293.17.

Comments on § 293.24(b)

Several commenters questioned the Department's inclusion of Tribal infrastructure projects in § 293.24(b) and noted provisions addressing those projects may be beneficial to Tribes.

The Department acknowledges the comments. The Department notes that infrastructure projects may be beneficial for Tribes. The Department included Tribal infrastructure in § 293.24(b) to highlight that these projects should not be ''considered directly related to the Tribe's conduct of gaming'' simply because they may be funded using gaming revenue or may provide a benefit to the gaming facility.

Several commenters requested the Department remove the word ''incidental'' from § 293.24(b). Commenters noted the phrase ''incidental benefits'' may cause confusion and result in unintended State overreach.

The Department has removed the word ''incidental'' from § 293.24(b).

Comments on § 293.24(c)

One commenter requested the Department revise § 293.24(c) to state ''Provisions which the Department may consider not directly related to the operation of gaming activities includes . . .''

The Department declines to adopt the requested revision.

Several commenters raised concerns with the Department's interpretation in § 293.24(c)(1) that ''[l]imiting third party Tribes' rights to conduct gaming'' is not directly related to operation of gaming activities under 25 U.S.C. 2710(d)(3)(C)(vii). Several commenters requested clarification and noted the Department has approached compact provisions impacting third party Tribes differently and cited to the Department's discussion and approval of ''section 9'' in the 1993 Michigan compacts. Other commenters noted that § 293.24(c)(1) could include Tribal parity provisions or 'most favored nation' provisions. Other commenters recommended the Department remove this provision arguing it is ambiguous and potentially limits geographic exclusivity provisions. Other commenters applauded § 293.24(c)(1) and noted it appeared consistent with the Departments long standing objection to compact provisions which sought to limit third party Tribes' rights under IGRA.

The Department acknowledges the comments. The Department has consistently distinguished compacts with Statewide gaming market regulatory scheme from compacts which limit third party Tribes rights under IGRA. In both Michigan and Arizona, the States and the Tribes negotiated mutually beneficial agreements addressing the location and size of Tribal gaming as part of a Statewide scheme. These and similar compacts included Tribe-to-Tribe revenue sharing provisions to offset market disparities between urban and rural Tribes. These compacts are identical across the State or contain identical relevant provisions. The Department has consistently found

[6] *See, e.g., Chicken Ranch Ranchera of Me-Wuk Indians* v. *California,* 42 F.4th 1024, 1063 (9th Cir. 2022).

these types of agreements consistent with IGRA.[7]

These are contrasted by compacts which act to prevent a Tribe, who is not party to the compact or the broader Statewide scheme, from exercising its full rights to conduct gaming under IGRA, most notably in the form of geographic exclusivity from Tribal competition. The Department has consistently expressed concern with these types of arrangements, and in some cases disapproved compacts containing such provisions.[8] The Department has not limited this provision to ''anti-compete'' or ''geographic exclusivity from Tribal competition'' to permit the Secretary flexibility in evaluating other provisions which may also improperly limit a third-party Tribe's rights under IGRA.

Commenters recommended the Department include examples of ''non-gaming Tribal economic activities'' to clarify the Department's standard articulated in § 293.24(b).

The Department has included examples of non-gaming Tribal economic development in § 293.24(c)(8).

Comments on § 293.24—Which Has Been Renumbered as § 293.25—What factors will the Secretary analyze to determine if revenue sharing is lawful?

The Department has renumbered the proposed § 293.24 as § 293.25 and comments have been edited to reflect the new section number.

A number of commenters responded to the Department's fifth consultation question: ''[s]hould the draft revisions include provisions that identify types of meaningful concessions that a Tribe may request from State, other than protection from State-licensed commercial gaming (*i.e.,* exclusivity), for which a Tribe could make revenue-sharing payments? How would such provisions affect compact negotiations?'' Many commenters expressed support for including an illustrative list of potential concessions similar to the lists in § 293.24. Commenters noted such a list would aid negotiating parties in identifying types of concessions a State may offer in exchange for revenue sharing. Commenters suggested examples could include: geographic exclusivity, Statewide mobile sports wagering, and a Governor's concurrence in a Secretarial Two-Part Determination under section 2719(b)(1)(A). Other commenters opposed including an illustrative list of potential concessions similar to the lists in § 293.24. Those commenters noted States may improperly use such a list to demand revenue sharing while offering a concession of limited value to the Tribe. Commenters recommended the Department follow a case-by-case evaluation which provides negotiating parties flexibility.

The Department acknowledges the comments and notes these comments highlight the sensitive nature of revenue sharing in compacts. The Department declines to include a list of meaningful concessions as both the concession and the revenue sharing rate must be evaluated on a case-by-case basis. The Department has approved revenue sharing in exchange for meaningful concessions including geographic exclusivity from State-licensed gaming and Statewide mobile or i-gaming exclusivity.[9] The Department cautions parties not to negotiate for a future meaningful concession which may require intervening Federal or State actions as that concession may be considered illusory.

A number of commenters expressed support for the proposed § 293.25. Commenters noted the proposed § 293.25 appeared to codify existing case law as well as the Department's articulation of the test for determining if revenue sharing is appropriately bargained for exchange or an improper tax. Commenters noted that some States seek to require—or heavily incentivize—intergovernmental agreements with political subdivisions of the State, such as a local government, requiring payments by the Tribe as a disguised tax. Commenters noted this will assist parties in compact negotiations by clearly articulating the Department's test for evaluating revenue sharing. Several commenters recommended the Department review revenue sharing provisions in compacts on a case-by-case basis with deference to a Tribe's sophisticated negotiations and cautioning against a paternalistic review.

The Department acknowledges the comments and notes the proposed § 293.25 codifies the Department's longstanding test for evaluating revenue sharing. The Department included payments to local governments in §§ 293.4, 293.8, 293.25, and 293.28, in an effort to address mandated intergovernmental agreements which may disguise improper taxes.

Several commenters requested the Department define ''meaningful concession'' and ''substantial economic benefit.'' Commenters proposed the Department define meaningful concession as: (1) something of value to the Tribe; (2) related to gaming; (3) which carries out the purposes for which the IGRA was enacted, and (4) which is not a proper subject of negotiation that the State already has an obligation to negotiate with the Tribe under IGRA.

The Department accepted this comment. A new definition for ''meaningful concession'' is adopted in § 293.2, which reads as follows: a ''meaningful concession'' is: (1) something of value to the Tribe; (2) directly related to gaming; (3) something that carries out the purposes of IGRA, and (4) not a subject over which a State is otherwise obligated to negotiate under the IGRA.

A new definition for ''substantial economic benefits'' is adopted in § 293.2, which reads as follows: ''substantial economic benefits'' is: ''(1) a beneficial impact to the Tribe, (2) resulting from a meaningful concession,

[7] *See, e.g.,* Letter from Ada Deer, Assistant Secretary—Indian Affairs to Jeff Parker, Chairperson, Bay Mills Indian Community dated November 19, 1993, approving the 1993 Michigan Compact; Letter from Bryan Newland, Principal Deputy Assistant Secretary—Indian Affairs, to Robert Miguel, Chairman Ak-Chin Indian Community, dated May 21, 2021, at 2, discussing the Tribe-to-Tribe revenue sharing and gaming device leasing provisions.

[8] *See, e.g.,* Letter from Gale Norton, Secretary of the Interior, to Cyrus Schindler, Nation President, Seneca Nation of Indians dated November 12, 2002, discussing the limits placed on Tonawanda Band and the Tuscarora Nation in the Seneca Nation's exclusivity provisions, and describing such provisions as ''anathema to the basic notion of fairness in competition and . . . inconsistent with the goals of IGRA''; Letter from Aurene Martin, Assistant Secretary—Indian Affairs (acting), to Harold ''Gus'' Frank, Chairman, Forest County Potawatomi Community, dated April 25, 2003, addressing the parties removal of section XXXI.B which created a 50 mile 'no fly zone' around the Tribe's Menominee Valley facility and explained ''we find a provision excluding other Indian gaming anathema to basic notions of fairness in competition and inconsistent with the goals of IGRA''; Letter from Aurene Martin, Assistant Secretary—Indian Affairs (acting), to Troy Swallow, President, Ho-Chunk Nation, dated August 15, 2003, addressing section XXVII(b), limiting the Governor's ability to concur in a two-part Secretarial Determination under section 20(b)(1)(A) of IGRA for another Tribe as ''repugnant to the spirit of IGRA''; Letter from Kevin Washburn, Assistant Secretary—Indian Affairs, to Harold Frank, Chairman, Forest County Potawatomi Community dated January 9, 2013, disapproving an amendment which would have made the Menominee Tribe guarantee Potawatomi's Menominee Valley facility profits as a condition of the Governor's concurrence for Menominee's Kenosha two-part Secretarial Determination, *affirmed by Forest Cty. Potawatomi Cmty.* v. *United States,* 330 F. Supp. 3d 269 (D.D.C. 2018). *See also* Letter from Bryan Newland, Assistant Secretary—Indian Affairs to Claudia Gonzales, Chairwoman, Picayune Rancheria of Chukchansi Indian of California, dated November 5, 2021, at 13.

[9] *See, e.g.,* Letter from Bryan Newland, Assistant Secretary—Indian Affairs to the Honorable R. James Gessner, Jr., Chairman, Mohegan Tribe of Indians dated September 10, 2021, approving the Tribe's compact amendment with the State of Connecticut; and Letter from Bryan Newland, Assistant Secretary—Indian Affairs to the Honorable Rodney Butler, Chairman, Mashantucket Pequot Indian Tribe dated September 10, 2021, approving the Tribe's amendment to its Secretarial Procedures, as amended in agreement with the State of Connecticut.

(3) made with a Tribe's economic circumstances in mind, (4) spans the life of the compact, and (5) demonstrated by an economic/market analysis or other similar documentation submitted by a Tribe or a State.''

Several commenters requested the Department include a requirement within §§ 293.8 and 293.25 for the compacting Tribe to submit a market analysis to demonstrate that any revenue sharing arrangements will provide actual benefits to the Tribe which justify the payment amount.

The Department acknowledges the comments. The Department has added the requested requirement to §§ 293.8 and 293.25. Section 293.8(e) is amended to require a Tribe or a State to submit a market analysis along with their compact when the compact contains revenue sharing provisions. Additionally, § 293.25(b)(2) is amended to include ''the value of the specific meaningful concessions offered by the State provides substantial economic benefits to the Tribe in a manner justifying the revenue sharing required by the compact.''

Several commenters requested the Department include IGRA's primary beneficiary test to the Department's revenue sharing analysis.

The Department acknowledges the comments. The Department has added the requested requirement to § 293.25 as a new § 293.25(b)(3), which now requires evidence showing that the Tribe is the primary beneficiary of its conduct of gaming, if the parties adopt revenue sharing.

A number of commenters described their varying experiences under differing revenue sharing arrangements. Some noted revenue sharing has become a necessary negotiation tactic to bring a reluctant State to the negotiation table after the Supreme Court's decision in *Seminole.* Some commenters discussed revenue sharing with local governments through intergovernmental agreements. Others noted that some particularly high revenue sharing rates based on gross revenue have resulted in the State receiving more revenue than the Tribe's portion of the net revenue. Commenters also discussed situations when States have either actively sought to undermine the Tribe's exclusivity—while not technically violating the compact—or refusing to enforce State law to protect the Tribe's exclusivity.

The Department acknowledges these comments. The Department has long expressed concern with relatively high revenue sharing arrangements, often permitting compacts containing them to go into effect and occasionally disapproving them. The Department's understanding of revenue sharing provisions, as well as exclusivity provisions, has evolved consistent with case law and experiences of Tribes operating under differing revenue sharing provisions for more than 30 years. The Department has long offered, and will continue to offer, technical assistance—highlighting the Department's precedents as well as observed best practices—to parties negotiating revenue sharing provisions.

A number of commenters questioned the Secretary's authority to review revenue sharing with ''great scrutiny'' or include a bad faith standard to evaluations of revenue sharing provisions. One commenter opined revenue sharing payments are an improper workaround for IGRA's prohibition on the assessment of a tax, fee, charge, or other assessment. Other commenters expressed concern with the proposed § 293.25 and cautioned the proposed provisions may cause unintended consequences including limiting a Tribe's options to contribute reasonable revenue share to a State to protect exclusivity or redistribute funds to non-gaming Tribes. One commenter opined the Department's past precedents on revenue sharing and exclusivity is suspect, citing the Department's decisions in New Mexico and New York and questioning the value of the exclusivity over the lives of those compacts.

The Department acknowledges the comments. The proposed regulations codify the Department's longstanding test for determining when revenue sharing in a compact is a prohibited ''tax, fee, charge, or other assessment'' because it goes beyond what is permitted by guidance in relevant court decisions. The Department notes that its evaluation of revenue sharing has evolved to incorporate changes in case law including *Rincon* v. *Schwarzenegger,* 602 F.3d 1019 (9th Cir. 2010). The Department finds persuasive, but not binding, the language in *Rincon* where the Ninth Circuit explained that IGRA requires courts to consider a State's demand for taxation as *evidence* of bad faith, not conclusive proof (citing *In re Indian Gaming Related* Cases (*Coyote Valley II*), 331 F.3d 1094, 1112–13 (9th Cir. 2003), which in turn cited section 2710(d)(7)(B)(iii)(II)). The Department's great scrutiny standard is consistent with IGRA's prohibition on a State demanding a tax, fee, charge, or other assessment under section 2710(d)(4) and IGRA's instruction to the courts in section 2710(d)(7)(B)(iii)(II). The Department notes the Secretary expressed concerns with the exclusivity provisions in both the 2015 New Mexico deemed approval letters and the 2002 Seneca Nation deemed approval letter but deferred to the judgment of the Tribes.[10] As explained above, the Department has replaced the phrase ''evidence of bad faith'' with ''evidence of a violation of IGRA.''

Several commenters suggest the Department expand the bad faith standard in § 293.24(c). Some commenters requested the Department include a State's continued insistence that the Tribe accept the proposed ''meaningful concession'' in exchange for revenue sharing as evidence of bad faith. Commenters opined that the provision is consistent with the Ninth Circuit's analysis of the issue in *Rincon Band* v. *Schwarzenegger,* 602 F.3d 1019 (9th Cir. 2010). Other commenters requested the Department include a State's request for revenue sharing, or insistence on a specified rate paid by other Tribes, either in the State or in a neighboring State, or past rates that are no longer supported by the current market, as presumptive evidence of bad faith. Other commenters requested the Department include a State's disparate treatment of similarly situated Tribes in the State as presumptive evidence of bad faith.

The Department declines to include additional examples as bad faith or adopt a ''presumptive bad faith'' standard. As explained above, the Department has replaced the phrase ''evidence of bad faith'' with ''evidence of a violation of IGRA.'' The compact negotiation process in IGRA envisions a negotiation between two sovereigns, although the Department notes in some instances Tribes have successfully engaged in collective negotiations with the State. If a State makes an offer which the Tribe rejects, the Tribe may make a counteroffer. The IGRA provides that if a State does not negotiate, or does not negotiate in good faith, the remedial provisions of the statute permit a Tribe to bring an action in Federal district court. The Department will continue to coordinate with the Department of Justice and the National Indian Gaming Commission regarding enforcement of IGRA.

Some commenters requested the Department revise § 293.25 to require the Tribe to initiate revenue sharing negotiations and to tie the revenue sharing provision's specific payments to specific concessions. The proposed revised text would read: ''(1) the Tribe

[10] *See* Letter from Gale Norton, Secretary of the Interior, to Cyrus Schindler, Nation President, Seneca Nation of Indians dated November 12, 2002; *see also* Letter from Kevin Washburn, Assistant Secretary—Indian Affairs, to Ty Vicenti, President, Jicarilla Apache Nation, dated June 9, 2015.

requested and the State has offered specific meaningful concessions the State was otherwise not required to negotiate; and (2) the value of the specific meaningful concessions offered by the State provides substantial economic benefits to the Tribe in a manner justifying the revenue sharing required by the compact.''

The Department accepts the requested revision as § 293.25(b)(1) and (2).

One commenter requested the Department include a provision in § 293.25 permitting the Tribe, during the life of the compact, to request technical assistance or a legal opinion if the meaningful concession continues to provide substantial economic benefits to the Tribe justifying continued revenue sharing payments and, if not, to what extent the revenue sharing payments should be adjusted to remain in compliance with IGRA.

The Department declines to adopt the requested provision in § 293.25. The Department will continue to offer technical assistance to Tribes and States, including identification of best practices. The Department notes best practices include careful drafting of both the terms of the Tribe's exclusivity—or other meaningful concession—along with remedies for breach and triggers for periodic renegotiation of specific provisions.

Several commenters requested the Department clarify that a State's obligation under IGRA to negotiate a compact is not a ''meaningful concession'' for the purposes of revenue sharing.

The Department acknowledges the comments. Congress required Tribes and States to negotiate class III gaming compacts in good faith, provided a remedy if States refused to negotiate in good faith, limited the scope of bargaining for class III gaming compacts, and prohibited States from using the process to impose any tax, fee, charge or other assessment on Tribal gaming operations. 25 U.S.C. 2710(d).

Several commenters noted the proposed § 293.25, while helpful for most Tribes and States, is without a *Seminole* fix effectively a dead letter.

The Department has addressed comments requesting a *Seminole* fix above under general comments. There the Department notes it has long coordinated with the Department of Justice and the National Indian Gaming Commission regarding enforcement of IGRA.

Several commenters requested the Department clarify that the result of a ''bad faith'' determination under § 293.25 would result in automatic disapproval of the compact or amendment.

The Department declines to establish an automatic disapproval standard. As explained above, the Department has replaced the phrase ''evidence of bad faith'' with ''evidence of a violation of IGRA.'' The Secretary's discretion to disapprove or take no action is discussed under §§ 293.12, 293.15, and 293.16.

One commenter noted that the proposed regulation at § 293.25, when read in conjunction with § 293.24, is ambiguous and needs to be clarified. The two proposed regulations, taken together, seem to imply that the ''meaningful concession exception'' is limited to a State's demand for a fee.

The Department acknowledges the comments. The Department notes § 293.24 addresses provisions which are considered ''directly related to gaming'' while § 293.25 addresses revenue sharing. The Department also notes the recent decision by the Ninth Circuit in *Chicken Ranch* overturned the district court's application of the meaningful concession test to provisions which were tangentially related to gaming. The Department finds the Ninth Circuit's reasoning persuasive, but not binding, that meaningful concessions cannot make an out-of-scope topic proper under IGRA. *Chicken Ranch Ranchera of Me-Wuk Indians* v. *California,* 42 F.4th 1024 (9th Cir. 2022)

Comments on § 293.25—Which Has Been Renumbered as § 293.26—May a compact or extension include provisions that limit the duration of the compact?

The Department has renumbered the proposed § 293.25 as § 293.26 comments have been edited to reflect the new section number.

Several commenters expressed support for the proposed § 293.26 and explained compacts should be very long term or perpetual. Commenters noted the negotiation process can be lengthy and require a significant investment of resources.

The Department acknowledges the comments.

Several commenters expressed support for the inclusion of a bad faith standard in the proposed § 293.26. Several commenters requested the Department add the word ''presumptive'' so the relevant sentence would read ''[a] refusal to negotiate a long-term compact, or a short-term extension to allow for negotiations to continue, is considered presumptive evidence of bad faith.''

The Department acknowledges the comments but declines the requested revision. As explained above the Department has replaced the phrase ''evidence of bad faith'' with ''evidence of a violation of IGRA.''

One commenter requested the Department define ''long-term'' as at least 15-years, and ''short-term'' as at least one year.

The Department declines the proposed definition of ''at least 15-years'' for long term but has accepted the proposed definition of ''at least 1 year'' for short term.

Several commenters requested the Department clarify that the existence of a compact with a Tribe does not negate a State's obligation to negotiate a new compact or an amended compact for the period after the current compact expires.

The Department acknowledges the comments. The Department notes IGRA at 25 U.S.C. 2710(d)(3)(A) obligates a State to negotiate with a Tribe in good faith at the request of the Tribe. The existence of a compact does not absolve the State of its duty under IGRA.

Comments on § 293.26—Which Has Been Renumbered as 293.27—May a compact or amendment permit a Tribe to engage in any form of class III gaming activity?

The Department has renumbered the proposed § 293.26 as 293.27 comments have been edited to reflect the new section number.

Several commenters expressed their support for this provision, noting that it will assist Tribes in negotiating scope of gaming provisions.

The Department acknowledges the comments.

A few commenters, while expressing support for the provision, stated that the provision was unclear as to its intent, and requested that the Department clarify that ''any'' means ''all.'' One commenter suggested the Department modify the second sentence to clarify the intent of the provision as follows: ''A State's refusal to negotiate a compact over all forms of class III gaming if it allows any form of class III gaming, is considered evidence of bad faith.'' While one commenter suggested the Department revise the second sentence to remove ''not prohibited by the State.''

The Department acknowledges the comments but declines the requested revisions. As explained above, the Department has replaced the phrase ''evidence of bad faith'' with ''evidence of a violation of IGRA.'' The language used by the Department follows the authority granted by IGRA.

One commenter noted that the term ''not prohibited'' has been the subject of much debate, interpretation, and litigation since IGRA was enacted and that a State, although its laws may prohibit such gaming, the State allows it to occur through non-enforcement. The commenter suggested that the Department revise the provision to make it clear that the mere existence of laws which state that class III gaming or a form of class III gaming is prohibited alone are not determinative of whether a State in fact prohibits class III gaming or a form of class III gaming, and that the Department will also examine the State's policies and practices regarding enforcement of laws that purport to prohibit class III gaming or a form of class III gaming in determining whether a State in fact prohibits such gaming.

The Department acknowledges the comment but declines the requested revision. The language used by the Department follows the authority granted by IGRA.

Many commenters, while expressing support for the provision, noted that courts have disagreed with this approach, particularly the Tenth Circuit, Ninth Circuit, and Eighth Circuit, where those courts adopted a narrower interpretation of the term ''permits such gaming,'' adopting the view that the phrase ''such gaming'' refers to specific types of class III games that a State permits. These commenters expressed concern that the provision is thus inconsistent with these more recent Federal court decisions and may lead to unnecessary litigation and cause some confusion and obstruction in future compact negotiations. One commenter questioned the language of § 293.27, noting that there is a body of Federal case law regarding the distinction between ''permitted'' and ''prohibited'' gaming activities. The commenter did not believe that § 293.27 adds value to existing case law.

The Department acknowledges these comments. The Department takes the position that the Second Circuit's decision in *Mashantucket Pequot Tribe* v. *Connecticut,* 913 F. 2d 1–24 (2d Cir. 1990) holding that Congress intended to codify the test set out in *California* v. *Cabazon Band of Mission Indians,* 480 U.S. 202 (1987) when it used the phrase ''permits such gaming'' such that IGRA refers to class III gaming categorically is correct. Under the Secretary's delegated authority to interpret and promulgate rules for IGRA, the Department finds that if a State allows any form of class III gaming, it is regulating all forms of class III gaming, which are a subject for good faith negotiations.

One commenter stated that § 293.27 appears to take a broader approach in scope of class III games and that it was unclear whether as currently drafted if § 293.27 speaks in class III games regulated by the State and not prohibited in the State and how provisions regarding Statewide remote wagering or internet wagering would be addressed under this provision.

The Department acknowledges this comment. § 293.27 provides that if a State allows any form of class III gaming, the State is regulating all forms of class III gaming, which are permitted under IGRA and thus a subject for good faith negotiations. In response to comments received during consultation the Department has added a new proposed section addressing i-gaming, § 293.29.

Several commenters suggested that a State's refusal to allow all forms of class III gaming as allowed under a State's constitution or other laws should be considered presumptive evidence of bad faith.

The Department acknowledges these comments but declines to make this revision. IGRA does not permit a presumptive determination of bad faith. Additionally, as explained above the Department has replaced the phrase ''evidence of bad faith'' with ''evidence of a violation of IGRA.''

Comments on § 293.27—Which Has Been Renumbered as § 293.28—May any other contract outside of a compact regulate Indian gaming?

The Department has renumbered the proposed § 293.27 as § 293.28 and comments have been edited to reflect the new section number.

Several commenters expressed support for the proposed § 293.28.

The Department acknowledges the comments.

Several commenters expressed concern with proposed § 293.28. Commenters stated that the provisions requiring Tribes to submit all the agreements encompassed under § 293.28 and § 293.4(b) are overly broad and should be revised to ensure they do not impact existing jurisdiction agreements, in lieu tax agreements, mutual aid agreements for law enforcement, health and safety agreements, alcohol regulation agreements, utility agreements, necessary roadway improvements, lending agreements, vendor agreements, and intergovernmental agreements with units of local governments. Commenters assert that the breadth of § 293.28 would create doubt over the validity of many existing jurisdiction agreements, undermine Tribal sovereignty, and interfere with the Tribes' ability to negotiate necessary local agreements according to what the Tribe believes is in its best interest based on its circumstances and experience.

Other commenters stated that the proposed new requirement for the Secretary to approve any ''Agreements which include provisions for the payment from a Tribe's gaming revenue . . . .'' is unnecessary and will result in the submission of an ''exponential'' number of agreements to the Office of Indian Gaming causing unnecessary delay and creating new roadblocks to a Tribe's economic development efforts. Moreover, offering a vague declination type remedy, with no time limit on agency action and no deemed approval mechanism will create further unnecessary delay. Further, IGRA at 25 U.S.C. 2710(d)(3) specifies ''compacts'' that are executed between Tribes and States under Federal and applicable State law, not counties or other political subdivisions of the State.

The Department accepted the comments, in part. Section 293.28 is modified to indicate that only agreements between Tribes and States, or States' political subdivisions, which govern gaming and include payments from gaming revenue, are covered by this section. Agreements that do not regulate gaming need not be submitted to the Department for approval as part of a Tribal-State gaming compact. Likewise, agreements between Tribes and the State and/or local governments that facilitate cooperation and good governance, but that do not regulate gaming, should not be incorporated into or referenced as a requirement of a Tribal-State gaming compact. Additionally, the Department has revised § 293.4(b) to require the Department to issue a determination whether a submitted document is a compact or amendment within 60 days of it being received and date stamped by the Office of Indian Gaming.

Several commenters requested the Department revise § 293.28 to permit rather than require a Tribe to submit the targeted documents and narrow which documents are targeted. Commenters explained the proposed revisions to § 293.28 would ensure that compacts and amendments do not include provisions that are not directly related to the operation of a Tribe's class III gaming operation. Commenters stated Tribes should have the option to request the Department's review and approval of other agreements, mandated or required by a compact or amendment, that do not exceed the scope permitted under IGRA.

The Department accepted the requested revisions. The Department revised § 293.28 to reflect the section only covers agreements between a Tribe and a State or the State's political subdivisions, which regulates the

Tribe's right to conduct gaming or includes payments from the Tribe's gaming revenue. The Department has also revised § 293.4 as discussed above. Agreements between a Tribe and the State and/or local governments that facilitate cooperation and good governance, but that do not regulate gaming or include payments from gaming revenue, should not be incorporated into, or referenced as a requirement of, a Tribal-State gaming compact.

Several commenters requested the Department revise proposed § 293.28, to exclude lending/loan agreements. The commenter argued the proposed language in § 293.28 would require Tribes to send lending agreements (loan documents) for Department review and approval under IGRA because it is not uncommon for lending agreements to require a Tribe hold gaming revenue in accounts for collateral or similar purposes. Commenters questioned if the Department intends to review financial documentation and lending agreements between Tribes and third-party lenders, which are subject to the National Indian Gaming Commission's review to determine if the agreement constitutes a management contract. Commenters opined subjecting lending agreements to review by the Department and the National Indian Gaming Commission would be extremely burdensome.

The Department accepted the requested revisions. The Department revised § 293.28 to reflect the section only covers agreements between a Tribe and a State or the State's political subdivisions, which regulates the Tribe's right to conduct gaming or includes payments from the Tribe's gaming revenue. Third-party agreements, such as lending documents and regular course of business agreements need not be submitted to the Department for approval as part of a Tribal-State gaming compact.

Several commenters questioned the Secretary's authority to review all documents included in the proposed § 293.28. Commenters explained section 2710(d)(3) of IGRA specifies that compacts are executed between Tribes and States under Federal and applicable State law, not counties or other political subdivisions of the State. Commenters explained this provision would arguably require submission of a vast number of agreements between Tribes and State and local governments. Commenters asserted that the use of gaming revenue is governed by 25 U.S.C. 2710(b)(2)(B) and many compacts and gaming ordinances have similar requirements. Commenters argued policing non-compact agreements, which call for payment from gaming revenue, is far afield of the Secretary's limited authority to approve or disapprove a compact.

The Department acknowledges the comments. IGRA directs that the Secretary review and either approve or disapprove compacts within a 45-day review period. In enacting IGRA, Congress delegated authority to the Secretary to review compacts to ensure that they comply with IGRA, other provisions of Federal law that do not relate to jurisdiction over gaming on Indian lands, and the trust obligations of the United States. 25 U.S.C. 2710(d)(8)(B)(i)–(iii). IGRA establishes a limited scope of appropriate topics in a Tribal-State gaming compact. Thus, in reviewing submitted compacts and amendments, the Secretary is vested the authority to determine whether the compacts contain topics outside IGRA's limited scope. IGRA limits a Tribe's use of gaming revenue to: funding Tribal governmental operations or programs; providing for the general welfare of the Tribe and its members; promoting Tribal economic development; donating to charitable organizations; or help fund operations of local governmental agencies. 25 U.S.C. 2710(b)(2)(B). However, IGRA in section 2710(d)(4) prohibits the State or its political subdivisions from imposing a tax, fee, charge, or other assessment. The Department reads section 2710(b)(2)(B) to permit a Tribe to voluntarily help fund operations of local governmental agencies, not as an end-run around the prohibition against imposed taxes, fees, charges, or other assessments in section 2710(d)(4). Section 293.25 includes a discussion of the Department's interpretation of IGRA's prohibition against the imposition of a tax, fee, charge, or other assessment.

Comments on § 293.28—Which Has Been Renumbered as § 293.31—How does the Paperwork Reduction Act affect this part?

The Department has renumbered the proposed § 293.28 as § 293.31 comments have been edited to reflect the new section number.

Several commenters expressed support for the proposed § 293.31.

The Department acknowledges the comments and notes the proposed § 293.31 is the renumbered but unrevised § 293.16 in the Department's 2008 Regulations.

V. Summary of Changes by Section

The Department proposes to provide primarily technical amendments to the existing process-based regulations, including the title. The proposed technical amendments are intended to clarify the process and contain edits for internal consistency and improved readability. The Department also proposes to add 15 sections addressing substantive issues and organize part 293 into 4 subparts. The Department proposes to amend the title to part 293 by removing the word ''process'' from the title. The proposed amended title would be ''part 293 Class III Tribal State Gaming Compacts.'' The Proposed Amendments incorporate comments received during Tribal consultation on the Consultation Draft and discussed above in the Tribal Consultation section.

A. Proposed Subpart A—General Provisions and Scope

The Proposed Subpart A, titled ''General Provisions and Scope'' would contain §§ 293.1 through 293.5.

Proposed Amendments to § 293.1—What is the purpose of the part?

The Department proposes technical amendments to clarify that the proposed part 293 Regulations contain both procedural and substantive regulations.

Proposed Amendments to § 293.2—How are key terms defined in this part?

The Proposed Amendment restructures the existing § 293.2 by removing the paragraph for the introductory sentence and editing that sentence for clarity. The proposed restructuring improves clarity by using the paragraphs for each defined term. The existing definitions for *Amendment, Compact* or *Tribal-State Gaming Compact,* and *Extension* reflect proposed edits to improve clarity and respond to comments received during consultation. The Proposed Amendments includes seven new definitions: *gaming activity* or *gaming activities, gaming facility, gaming spaces, IGRA, meaningful concession, substantial economic benefit,* and *Tribe.*

- *Gaming activity* or *gaming activities* are interchangeable terms repeatedly used in IGRA but not defined by IGRA. Therefore, the Department proposes to define these terms as used in part 293 and in Tribal-State gaming compacts as ''the conduct of class III gaming involving the three required elements of chance, consideration, and prize.''
- *Gaming Facility* is a term used in IGRA at 25 U.S.C. 2710(d)(3)(C)(vi), but is not defined by IGRA. IGRA permits a compact to include ''standards for the operation of such activity and maintenance of the gaming facility, including licensing.'' As a result, compacting parties have on occasion used this provision to extend State regulatory standards beyond the

maintenance and licensing of the physical structure where the Tribe is conducting gaming. The definition of *gaming facility* addresses building maintenance and licensing under the second clause of 25 U.S.C. 2710(d)(3)(C)(vi) and is intended to be narrowly applied to only the building or structure where the gaming activity occurs. Therefore, the Department proposes to define *gaming facility* as ''the physical building or structure where the gaming activity occurs.'' [11]

- *Gaming spaces* is a term the Department has used to clarify the physical spaces a compact may regulate. The Department proposed to define *Gaming Spaces* as ''the areas within a *Gaming Facility* that are directly related to and necessary for the conduct of class III gaming such as: the casino floor; vault; count room; surveillance, management, and information technology areas; class III gaming device and supplies storage areas; and other secured areas. where the operation or management of class III gaming takes place, including the casino floor, vault, count, surveillance, management, information technology, class III gaming device, and supplies storage areas.''
- *IGRA* is the commonly used acronym for the Indian Gaming Regulatory Act of 1988 (Pub. L. 100–497) 102 Stat. 2467 dated October 17, 1988, (Codified at 25 U.S.C. 2701–2721 (1988)) and any amendments. The Department proposes to include IGRA as a defined term to facilitate consistency and readability in the regulations.
- *Meaningful concession* is a term the Department has adopted from Ninth Circuit caselaw as part of the Department's long-standing test for revenue sharing provisions. The Department proposes to define meaningful concession as: ''something of value to the Tribe; directly related to gaming; something that carries out the purposes of IGRA; and not a subject over which a State is otherwise obligated to negotiate under IGRA.''
- *Substantial economic benefit* is a term the Department has adopted from Ninth Circuit caselaw as part of the Department's long-standing test for revenue sharing provisions. The Department proposes to define substantial economic benefit as: a beneficial impact to the Tribe; resulting from a meaningful concession; made with a Tribe's economic circumstances in mind; spans the life of the compact; and demonstrated by an economic/market analysis or similar documentation submitted by the Tribe or the State.
- *Tribe*—the Department is proposing to include Tribe as a defined term to facilitate consistency and readability in the regulations.

Proposed Amendments to § 293.3—What authority does the Secretary have to approve or disapprove compacts and amendments?

The Proposed Amendment contains a conforming edit to existing § 293.3.

Proposed Amendments to § 293.4—Are compacts and amendments subject to review and approval?

The Proposed Amendments contains clarifying edits combining paragraphs (a) and (b) from the 2008 Regulations into a new paragraph (a); a new paragraph (b) which was proposed during Tribal consolation, and a new paragraph (c) which creates a process by which the Parties may seek a determination if an agreement or other documentation is a ''compact or amendment'' without submitting that agreement for review and approval pursuant to IGRA. These proposed changes clarify that any document between a Tribe and the State or its political subdivisions which establish, change, or interpret the terms of a Tribe's compact or amendment regardless of whether they are substantive or technical, must be submitted for review and approval by the Secretary. The Department is concerned that compacting parties have read the existing definition of Compact in § 293.2(b)(2) and the existing § 293.4, narrowly to exclude from Secretarial review a range of agreements or other documents which often impact the parties understanding and application of the terms of their compact, or payments made by a Tribe from gaming revenue. The Department is proposing a new paragraph (b) to clarify the scope of documents that may be considered an amendment and a new paragraph (c) to allow parties to seek a determination from the Department that their agreement is or is not a compact. This process is modeled on the National Indian Gaming Commission's practice of issuing declination letters for agreements which do not trigger NIGC's review and approval of management contracts as required by IGRA at 25 U.S.C. 2711.

Proposed Amendments to § 293.5—Are extensions to compacts subject to review and approval?

The Proposed Amendments contain clarifying edits for consistency and readability. Additionally, the Department is proposing to add a sentence which codifies the Department's long-standing practice that an extension must be published in the **Federal Register** to be in effect.[12]

B. Proposed Subpart B—Submission of Tribal-State Gaming Compacts

The Proposed Subpart B, titled ''Submission of Tribal-State Gaming Compacts'' would contain §§ 293.6 through 293.9.

Proposed Amendments to § 293.6—Who can submit a compact or amendment?

The Proposed Amendments contains conforming edits for consistency to § 293.6.

Proposed Amendments to § 293.7—When should the Indian Tribe or State submit a compact or amendment for review and approval?

The Proposed Amendments contains conforming edits for consistency to both the heading and the body of § 293.7.

Proposed Amendments to § 293.8—What documents must be submitted with a compact or amendment?

The Proposed Amendments contains conforming edits for consistency to § 293.8. Additionally, the Department is proposing to renumber the existing paragraphs and add a new paragraph (d). The proposed paragraph (d) would clarify that compact submission package should include any agreements between the Tribe and the State or its political subdivisions which are required by the compact or amendment and either involve payments made by the Tribe from gaming revenue, or restricts or regulates the Tribe's use and enjoyment of its Indian lands, as well as any ancillary agreements, documents, ordinances, or laws required by the compact which the Tribe determines is relevant to the Secretary's review. The Department's review of the compact includes analyzing if the provision(s) requiring ancillary agreements, documents, ordinances, or laws violate IGRA or other Federal law because the underlying agreement includes provisions prohibited by IGRA, and therefore the Secretary may disapprove the compact.

[11] *See, e.g.* Letter to the Honorable Peter S. Yucupicio, Chairman, Pascua Yaqui Tribe of Arizona, from the Director, Office of Indian Gaming, dated June 15, 2012, at 5, and fn. 9, discussing the American Recovery & Reinvestment Act of 2009 and the IRS's ''safe harbor'' language.

[12] *See, e.g.* Notice of Final Rulemaking Part 293, 73 FR 74004, 74007 (Dec. 5, 2008).

Proposed Amendments to § 293.9—Where should a compact or amendment be submitted for review and approval?

The Proposed Amendments contains conforming edits for consistency and proposed new sentence to permit electronic submission of compacts. The Office of Indian Gaming will accept and date stamp electronic submissions for the purpose of initiating the 45-day review period. The first copy of a compact or amendment that is received and date stamped initiates the 45-day review period.

C. Proposed Subpart C—Secretarial Review of Tribal-State Gaming Compacts

The Proposed Subpart C, titled ''Secretarial Review of Tribal-State Gaming Compacts'' would contain §§ 293.10 through 293.16. The Proposed Amendments include renumbering the existing § 293.14 *When may the Secretary disapprove a compact or amendment?* as § 293.16. Renumbering and renaming the existing § 293.15 *When does an approved or considered-to-have-been-approved compact or amendment take effect?* as § 293.14 *When does a compact or amendment take effect?* And adding a new § 293.15 *Is the Secretary required to disapprove a compact or amendment that violates IGRA?*

Proposed Amendments to § 293.10—How long will the Secretary take to review a compact or amendment?

The Proposed Amendments contains conforming edits for consistency to § 293.10.

Proposed Amendments to § 293.11—When will the 45-day timeline begin?

The Proposed Amendments contains conforming edits to § 293.11 for consistency with proposed changes to § 293.9, and a new sentence providing the Department will send an email confirming receipt of electronically submitted compacts or amendments including when the Secretary's 45-day review period ends.

Proposed Amendments to § 293.12—What happens if the Secretary does not act on the compact or amendment within the 45-day review period?

The Proposed Amendments contain clarifying edits for consistency and readability. Additionally, the Department proposes to include a new provision codifying the Department's practice of issuing letters informing the parties that the compact or amendment has been approved by operation of law after the 45th day. The letter may include guidance to the parties identifying certain provisions that are inconsistent with the Department's interpretation of IGRA—also known as Deemed Approval Letters.

Proposed Amendments to § 293.13—Who can withdraw a compact or amendment after it has been received by the Secretary?

The Proposed Amendments contains conforming edits for consistency to § 293.13.

Proposed Amendments to § 293.14—When does a compact or amendment that is affirmatively approved or approved by operation of law take effect?

The Proposed Amendments renumber the existing § 293.15 as § 293.14 to improve overall organization of the regulations. The Proposed Amendments contain clarifying edits for consistency and readability to both the heading and the body of § 293.14.

Proposed § 293.15—Is the Secretary required to disapprove a compact or amendment that violates IGRA?

The Proposed Amendments contain a new § 293.15, which clarifies IGRA's limits on the Secretary's authority to review compacts. Congress, through IGRA at 25 U.S.C. 2710 (d)(8), provided the Secretary with time-limited authority to review a compact and discretionary disapproval authority. Within this limited time period, the Secretary may approve or disapprove a compact. IGRA further directs that if the Secretary does not approve or disapprove a compact within IGRA's limited time frame for review, then the compact shall be considered to have been approved by the Secretary, but only to the extent the compact is consistent with the provisions of IGRA. 25 U.S.C. 2710(d)(8)(C). The Department notes that one Circuit has held that the Secretary must disapprove a compact if it violates any of the three limitations in IGRA and may not approve the compact by operation of law. *Amador County* v. *Salazar,* 640 F.3d 373, 381 (DC Cir. 2011). The Department, however, strongly disagrees with the court's holding, finding that it conflicts with and negates a specific provision of IGRA.

Proposed § 293.16—When may the Secretary disapprove a compact or amendment?

The Proposed Amendments renumber and restructure the existing § 293.14 as § 293.16 to improve overall organization of the regulations. Additionally, the Department proposes to renumber the existing paragraphs and add a new paragraph (b). The proposed paragraph (b) would clarify that if a compact submission package is missing the documents required by § 293.8 and the parties decline to cure the deficiency, the Department will presume that the compact or amendment violates IGRA.

D. Proposed Subpart D—Scope of Tribal-State Gaming Compacts

The Proposed Subpart D, titled ''Scope of Tribal-State Gaming Compacts'' would contain §§ 293.17 through 293.31. The Proposed Amendments include substantive provisions addressing the appropriate scope of a compact under IGRA. These provisions continue the question-and-answer approach utilized in the existing regulations. These provisions codify existing Departmental practice and provide compacting parties clear guidance on the appropriate scope of compact negotiations.

Proposed § 293.17—May a compact include provisions addressing the application of the Tribe's or State's criminal and civil laws and regulations?

The Proposed Amendments contains a new § 293.17 clarifying the appropriate scope of terms addressing the application of the criminal and civil laws and regulations in a compact. Congress through IGRA at 25 U.S.C. 2710(d)(3)(C)(i) provided that a compact may include provisions addressing the application of criminal and civil laws and regulations of the Tribe or the State that are directly related to, and necessary for, the licensing and regulation of the gaming activity.

Proposed § 293.18—May a compact include provisions addressing the allocation of criminal and civil jurisdiction between the State and the Tribe?

The Proposed Amendments contains a new § 293.18 clarifying the appropriate scope of terms addressing the allocation of criminal and civil jurisdiction in a compact. Congress through IGRA at 25 U.S.C. 2701(5) found that ''[T]ribes have the exclusive right to regulate gaming activity on Indian lands if the gaming activity is not specifically prohibited by Federal law and is conducted within a State which does not, as a matter of criminal law and public policy, prohibit such gaming activity.'' Congress then provided that a compact may include provisions addressing the allocation of criminal and civil jurisdiction between the Tribe and the State necessary for enforcement of the laws and regulations described in section 2710(d)(3)(C)(i). *See* IGRA at 25 U.S.C. 2710(d)(3)(C)(ii).

Proposed § 293.19—May a compact include provisions addressing the State's costs for regulating gaming activities?

The Proposed Amendments contains a new § 293.19 clarifying the appropriate scope of assessments by the State to defray the costs of regulating the Tribe's gaming activity. Congress through IGRA at 25 U.S.C. 2710(d)(3)(C)(iii) provided that a compact may include provisions relating to the assessment by the State of the gaming activity in amounts necessary to defray the costs of regulating the gaming activity. Congress through IGRA at 25 U.S.C. 2710(d)(4) clarified any assessments must be negotiated and at no point may a State or its political subdivisions impose any taxes, fees, charges, or other assessments upon a Tribe through the compact negotiations. The Proposed Amendments further clarify that the compact should include requirements for the State to show actual and reasonable expenses over the life of the compact and the absence of such provisions is considered evidence of a violation of IGRA.

Proposed § 293.20—May a compact include provisions addressing the Tribe's taxation of gaming?

The Proposed Amendments contains a new § 293.20 clarifying the appropriate scope of provisions addressing a Tribe's taxation of tribally licensed gaming activity. Congress through IGRA at 25 U.S.C. 2710(d)(3)(C)(iv) provided that a compact may include provisions relating to the Tribe's taxation of gaming activities in amounts comparable to the State's taxation of gambling. A Tribal-State gaming compact may not be used to address the Tribe's taxation of other activities that may occur within or near the Tribe's gaming facility. The inclusion of provisions addressing the Tribe's taxation of other activities is considered evidence of a violation of IGRA.

Proposed § 293.21—May a compact or amendment include provisions addressing the resolution of disputes for breach of the compact?

The Proposed Amendments contains a new § 293.21 clarifying the appropriate scope of provisions addressing remedies for breach of the compact. Congress through IGRA at 25 U.S.C. 2710(d)(3)(C)(v) provided that a compact may include provisions relating to remedies for breach of contract. Compacts often include alternative dispute resolution including binding arbitration as part of the parties' remedies for allegations of breach of contract. Despite the Department's existing regulations clarifying that compacts and all amendments are subject to Secretarial review, some compacting parties have resolved disputes in manners which seek to avoid Secretarial review. Therefore, the Department proposes § 293.21 to clarify that any dispute resolution agreement, arbitration award, settlement agreement, or other resolution of a dispute outside of Federal court must be submitted for review and approval by the Secretary. Further, the proposed § 293.21 references the § 293.4 determination process for review prior to formal submission of a dispute resolution agreement as an amendment. The inclusion of provisions addressing dispute resolution in a manner that seeks to avoid the Secretary's review is considered evidence of a violation of IGRA.

Proposed § 293.22—May a compact or amendment include provisions addressing standards for the operation of gaming activity and maintenance of the gaming facility?

The Proposed Amendments contains a new § 293.22 clarifying the appropriate scope of provisions addressing the Tribe's standards for the operation of the gaming activity as well as the Tribe's standards for the maintenance of the gaming facility, including licensing in a compact. Congress through IGRA at 25 U.S.C. 2710(d)(3)(C)(vi) provided that a compact may include provisions relating to standards for the operation of such activity and maintenance of the gaming facility, including licensing. The Department interprets 2710(d)(3)(C)(vi) narrowly as two separate clauses addressing separate Tribal and State interests. First, a compact may include provisions addressing the standards for the operation and licensing of the gaming activity. Second, a compact may include provisions addressing the maintenance and licensing of the gaming facility building or structure. The Proposed Amendments in § 293.2 includes definitions of both *gaming facility* and *gaming spaces* to provide parties with clarity regarding the appropriate limits of State oversite under IGRA. Any compact provisions addressing the maintenance and licensing of a building or structure must be limited to the building or structure where the gaming activity occurs—the *gaming facility.* Further, if a compact or amendment mandate that the Tribe adopt standards equivalent or comparable to the standards set forth in a State law or regulation, the parties must show that these mandated Tribal standards are both directly related to and necessary for, the licensing and regulation of the gaming activity.

Proposed § 293.23—May a compact or amendment include provisions that are directly related to the operation of gaming activities?

The Proposed Amendments contains a new § 293.23 clarifying a compact may include provisions that are directly related to the operation of gaming activities. Congress through IGRA at 25 U.S.C. 2710(d)(3)(C)(vii) provided that a compact may include provisions relating to any other subjects that are directly related to the operation of gaming activities. The Proposed Amendments in § 293.24 codify the Department's longstanding narrow interpretation of section 2710(d)(3)(C)(vi).

Proposed § 293.24—What factors will be used to determine whether provisions in a compact or amendment are directly related to the operation of gaming activities?

The Proposed Amendments contains a new § 293.24 which codifies existing case law and the Department's longstanding narrow interpretation of section 2710(d)(3)(C)(vi) as requiring a ''direct connection.'' The Department notes the Ninth Circuit in *Chicken Ranch* found the Department's longstanding direct connection test persuasive and consistent with the court's own independent analysis of IGRA and case law. The proposed § 293.24 provides compacting parties with examples of provisions which have a direct connection to the Tribe's conduct of class III gaming activities as well as examples the Department has found do not satisfy the direct connection test.

Proposed § 293.25—What factors will the Secretary analyze to determine if revenue sharing is lawful?

The Proposed Amendments contains a new § 293.25 which clarifies the appropriate scope of provisions addressing revenue sharing. Congress, through IGRA at 25 U.C.S. 2710 (d)(4), prohibited States from seeking to impose any tax, fee, charge, or other assessment upon an Indian Tribe or upon any other person or entity authorized by an Indian Tribe to engage in a class III activity. The Proposed Amendments codifies the Department's longstanding rebuttable presumption that any revenue sharing provisions are a prohibited tax, fee, charge, or other assessment. The Proposed Amendments also contains the Department's test to rebut that presumption.

Proposed § 293.26—May a compact or extension include provisions that limit the duration of the compact?

The Proposed Amendments contains a new § 293.26 which addresses the appropriate duration of a compact. The Department and IGRA anticipate that compacts are long-term agreements between a Tribe and a State that reflect carefully negotiated compromises between sovereigns.

Proposed § 293.27—May a compact permit a Tribe to engage in any form of class III gaming activity?

The Proposed Amendments contains a new § 293.27, which clarifies the appropriate scope of class III gaming that a State permits. Congress, through IGRA at 25 U.C.S. 2710(d)(1)(B), requires that a Tribe seeking to conduct class III gaming be located in a State that permits such gaming for any purpose by any person, organization, or entity.

The Department takes the position that the Second Circuit's decision in *Mashantucket Pequot Tribe* v. *Connecticut,* 913 F. 2d 1–24 (2d Cir. 1990) holding that Congress intended to codify the test set out in *California* v. *Cabazon Band of Mission Indians,* 480 U.S. 202 (1987) when it used the phrase ''permits such gaming'' such that IGRA refers to class III gaming categorically is correct. Under the Secretary's delegated authority to interpret and promulgate rules for IGRA, the Department finds that if a State allows any form of class III gaming, it is regulating all forms of class III gaming, which are a subject for good faith negotiations.

Proposed § 293.28—May any other contract outside of a compact regulate Indian gaming?

The Proposed Amendments contains a new § 293.28 which clarifies that any agreement between a Tribe and a State or its political subdivisions which seeks to regulate a Tribe's right to conduct gaming—as limited by IGRA—is a gaming compact that must comply with IGRA and be submitted for review and approval by the Secretary.

Proposed § 293.29—May a compact or amendment include provisions addressing Statewide remote wagering or internet gaming?

The Proposed Amendments contains a new § 293.29, which clarifies a compact may include provisions allocating jurisdiction to address Statewide remote wagering or internet gaming. The IGRA provides that a Tribe and State may negotiate for ''the application of the criminal and civil laws and regulations of the Indian Tribe or the State that are directly related to, and necessary for, the licensing and regulation of such activity'' and ''the allocation of criminal and civil jurisdiction between the State and the Indian Tribe necessary for the enforcement of such laws and regulations.'' 25 U.S.C. 2710(d)(3)(c)(i)-(ii). The Department's position is that the negotiation between a Tribe and State over Statewide remote wagering or i-gaming falls under these broad categories of criminal and civil jurisdiction. Accordingly, provided that a player is not physically located on another Tribe's Indian lands, a Tribe should have the opportunity to engage in this type of gaming pursuant to a Tribal-State gaming compact. The Department notes the ultimate legality of gaming activity outside Indian lands remains a question of State law, notwithstanding that a compact discusses the activity. However, Congress in enacting IGRA did not contemplate the Department would address or resolved complex issues of State law during the 45-day review period.[13] Further, non-IGRA Federal law may also place restrictions on that activity.

Proposed § 293.30—What effect does this part have on pending requests, final agency decisions already issued, and future requests?

The Proposed Amendments contains a new § 293.30 which clarifies the proposed regulations are prospective and the effective date of the proposed regulations.

Proposed § 293.31—How does the Paperwork Reduction Act affect this part?

The Proposed Amendments renumbers existing § 293.16 as § 293.31 to improve overall organization of the regulations.

VI. Procedural Requirements

A. Regulatory Planning and Review (E.O. 12866)

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 E.O. 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. E.O. 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. We have developed this rule in a manner consistent with these requirements.

B. Regulatory Flexibility Act

The Department of the Interior certifies that this proposed rule would not have a significant economic effect on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). This proposed rule would codify longstanding Departmental policies and interpretation of case law in the form of substantive regulations which would provide certainty and clarity on how the Secretary will review certain provisions in a compact.

C. Congressional Review Act (CRA)

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

- Does not have an annual effect on the economy of $100 million or more.
- Will not cause a major increase in costs or prices for consumers, individual industries, federal, State, or local government agencies, or geographic regions.
- 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.

D. Unfunded Mandates Reform Act of 1995

This rule would not impose an unfunded mandate on State, local, or Tribal governments, or the private sector of more than $100 million per year. The rule would not have a significant or unique effect on State, local, or Tribal governments or the private sector. A statement containing the information required by the Unfunded Mandates Reform Act (2 U.S.C. 1531 *et seq.*) is not required).

E. Takings (E.O. 12630)

This rule would not affect a taking of private property or otherwise have taking implications under Executive Order 12630 because this rulemaking, if adopted, does not affect individual

[13] *See, e.g., Pueblo of Santa Ana* v. *Kelly,* 104 F.3d 1546, 1556 (10th Cir. 1997).

property rights protected by the Fifth Amendment or involve a compensable ''taking.'' A takings implication assessment is not required.

F. Federalism (E.O. 13132)

Under the criteria in section 1 of Executive Order 13132, this rule would not have sufficient federalism implications to warrant the preparation of a federalism summary impact statement. A federalism summary impact statement is not required because, the Department seeks to codify longstanding Departmental policies and interpretation of case law in the form of substantive regulations which would provide certainty and clarity on how the Secretary will review certain provisions in a compact.

G. Civil Justice Reform (E.O. 12988)

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

• 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

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

H. Consultation With Indian Tribes (E.O. 13175)

The Department will conduct two virtual session, one in-person consultation, and will accept oral and written comments. The consultations sessions will be open to Tribal leadership and representatives of federally recognized Indian Tribes and Alaska Native Corporations.

• *In-Person Session:* The in-person consultation will be held on January 13, 2023, from 1 p.m. to 4 p.m. MST, at the BLM National Training Center (NTC), 9828 N. 31st Ave, Phoenix, AZ 85051.

• *1st Virtual Session:* The first virtual consultation session will be held on January 19, 2023, from 1 p.m. to 4 p.m. EST. Please visit *https://www.zoomgov.com/meeting/register/vJIsd-2qrjwiH2bVXpLvS2VPUZESt2HgtKk* to register in advance.

• *2nd Virtual Session:* The second virtual consultation will be held on January 30, 2023, from 2 p.m. to 5 p.m. EST. Please visit *https://www.zoomgov.com/meeting/register/vJIsduGtqzgtE1hw9EIFrDf3-X_1gy5wGR0* to register in advance.

• *Comment Deadline:* Please see **DATES** and **ADDRESSES** sections for submission instructions.

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. We have evaluated this rule under the Department's consultation policy and under the criteria in E.O. 13175 and have hosted extensive consultation with federally recognized Indian Tribes in preparation of this proposed rule, including through a Dear Tribal Leader letter delivered to every Federally-recognized Tribe in the country, and through three consultation sessions held on May 9, 13, and 23, 2022.

I. Paperwork Reduction Act

OMB Control No. 1076–0172 currently authorizes the collection of information related to Class III Tribal-State Gaming Compact Process, with an expiration of August 31, 2024. This rule requires no change to that approved information collection under the Paperwork Reduction Act (PRA), 44 U.S.C. 3501 *et seq.*

J. National Environmental Policy Act (NEPA)

This rule would 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 an administrative and procedural 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.

K. Effects on the Energy Supply (E.O. 13211)

This rule is not a significant energy action under the definition in Executive Order 13211. A Statement of Energy Effects is not required.

L. Clarity of This Regulation

We are required by Executive Orders 12866 (section 1 (b)(12)), 12988 (section 3(b)(l)(B)), and 13563 (section l(a)), and by the Presidential Memorandum of June 1, 1998, to write all rules in plain language. This means that each rule we publish must:

(a) Be logically organized;

(b) Use the active voice to address readers directly;

(c) Use common, everyday words and clear language rather than jargon;

(d) Be divided into short sections and sentences; and

(e) Use lists and tables wherever possible.

If you feel that we have not met these requirements, send us comments by one of the methods listed in the **ADDRESSES** section. To better help us revise the rule, your comments should be as specific as possible. For example, you should tell us the numbers of the sections or paragraphs that you find unclear, which sections or sentences are too long, the sections where you feel lists or tables would be useful, etc.

M. Public Availability 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.

List of Subjects 25 CFR Part 293

Administrative practice and procedure, Gambling, Indians-tribal government, State and local governments.

■ For the reasons stated in the preamble, the Department of the Interior, Bureau of Indian Affairs, proposes to revise 25 CFR part 293 to read as follows:

PART 293—CLASS III TRIBAL-STATE GAMING COMPACT

Subpart A—General Provisions and Scope

Subpart B—Submission of Tribal-State Gaming Compacts

Authority: 5 U.S.C. 301; 25 U.S.C. 2, 9, 2710.

Subpart A—General Provisions and Scope

§ 293.1 What is the purpose of this part?

This part contains:

(a) Procedures that Indian Tribes and/or States must use when submitting Tribal-State compacts and compact amendments to the Department of the Interior (Department); and

(b) Procedures and criteria that the Secretary of the Interior (Secretary) will use for reviewing such Tribal-State compacts or compact amendments.

§ 293.2 How are key terms defined in this part?

This part relies on but does not restate all defined terms set forth in the definitional section of IGRA.

(a) *Amendment* means:

(1) A change to a class III Tribal-State gaming compact other than an extension, or

(2) A change to secretarial procedures prescribed under 25 U.S.C. 2710(d)(7)(B)(vii) when such change is agreed upon by the Tribe and State.

(b) *Compact* or *Tribal-State Gaming Compact* means an intergovernmental agreement executed between Tribal and State governments under IGRA that establishes between the parties the terms and conditions for the operation and regulation of the Tribe's Class III gaming activities.

(c) *Extension* means an intergovernmental agreement executed between Tribal and State governments under IGRA to change the duration of a compact or amendment.

(d) *Gaming activity* or *gaming activities* means the conduct of class III gaming involving the three required elements of chance, consideration, and prize or reward.

(e) *Gaming facility* means the physical building or structure, where the gaming activity occurs.

(f) *Gaming spaces* means the areas within a gaming facility (as defined in paragraph (e) of this section) that are directly related to and necessary for the conduct of class III gaming such as: the casino floor; vault; count room; surveillance, management, and information technology areas; class III gaming device and supplies storage areas; and other secured areas. where the operation or management of class III gaming takes place, including the casino floor, vault, count, surveillance, management, information technology, class III gaming device, and supplies storage areas.

(g) *IGRA* means the Indian Gaming Regulatory Act of 1988 (Pub. L. 100–497) 102 Stat. 2467 dated October 17, 1988, (Codified at 25 U.S.C. 2701–2721 (1988)) and any amendments.

(h) *Meaningful concession* means:

(1) Something of value to the Tribe;

(2) Directly related to gaming;

(3) Something that carries out the purposes of IGRA; and

(4) Not a subject over which a State is otherwise obligated to negotiate under IGRA.

(i) *Substantial economic benefit* means:

(1) A beneficial impact to the Tribe;

(2) Resulting from a meaningful concession;

(3) Made with a Tribe's economic circumstances in mind;

(4) Spans the life of the compact; and

(5) Demonstrated by an economic/market analysis or similar documentation submitted by the Tribe or the State.

(j) *Tribe* means Indian Tribe as defined in 25 U.S.C. 2703(5).

§ 293.3 What authority does the Secretary have to approve or disapprove compacts and amendments?

The Secretary has the authority to approve a compact or amendment "entered into" by a Tribe and a State. See § 293.15 for the Secretary's authority to disapprove compacts or amendments.

§ 293.4 Are compacts and amendments subject to review and approval?

(a) Yes. All compacts and amendments, regardless of whether they are substantive or technical, must be submitted for review and approval by the Secretary.

(b) If an ancillary agreement or document:

(1) Changes a term to a compact, then it must be submitted for review and approval by the Secretary

(2) Implements or clarifies a provision contained in a compact or an amendment and is not inconsistent with an approved compact or amendment, it does not constitute a compact or an amendment and need not be submitted for review and approval by the Secretary.

(3) If an approved compact or amendment expressly contemplates an ancillary agreement or document, such as internal controls or a memorandum of agreement between the Tribal and State regulators, then such agreement or document is not subject to review and approval so long as it is not inconsistent with the approved compact or amendment.

(4) If an ancillary agreement or document interprets language in a compact or an amendment concerning the payment of a Tribe's gaming revenue or includes any of the topics identified in 25 CFR 292.24, then it may constitute

an amendment subject to review and approval by the Secretary.

(c) If a Tribe or a State (including its political subdivisions) are concerned that their agreement or other document, including, but not limited to, any dispute resolution agreement, arbitration award, settlement agreement, or other resolution of a dispute outside of Federal court, may be considered a ''compact'' or ''amendment,'' either party may request in writing a determination from the Department if their agreement is a compact or amendment and therefore must be approved and a notice published in the **Federal Register** prior to the agreement becoming effective. The Department will issue a letter within 60 days providing notice of the Secretary's determination.

§ 293.5 Are extensions to compacts or amendments subject to review and approval?

No. Approval of an extension to a compact or amendment is not required if the extension does not include any changes to any of the other terms of the compact or amendment. However, the parties must submit the documents required by § 293.8(a) through (c). The extension becomes effective only upon publication in the **Federal Register**.

Subpart B—Submission of Tribal-State Gaming Compacts

§ 293.6 Who can submit a compact or amendment?

Either party (Tribe or State) to a compact or amendment can submit the compact or amendment to the Secretary for review and approval.

§ 293.7 When should the Tribe or State submit a compact or amendment for review and approval?

The Tribe or State should submit the compact or amendment after it has been duly executed by the Tribe and the State in accordance with applicable Tribal and State law, or is otherwise binding on the parties.

§ 293.8 What documents must be submitted with a compact or amendment?

Documentation submitted with a compact or amendment must include:

(a) At least one original compact or amendment executed by both the Tribe and the State;

(b) A Tribal resolution or other document, including the date and place of adoption and the result of any vote taken, that certifies that the Tribe has approved the compact or amendment in accordance with applicable Tribal law;

(c) Certification from the Governor or other representative of the State that they are authorized under State law to enter into the compact or amendment;

(d) Any agreement between a Tribe and a State, its agencies or its political subdivisions required by a compact or amendment if the agreement requires the Tribe to make payments to the State, its agencies, or its political subdivisions, or it restricts or regulates a Tribe's use and enjoyment of its Indian Lands and any other ancillary agreements, documents, ordinances, or laws required by the compact or amendment which the Tribe determines is relevant to the Secretary's review; and

(e) Any other documentation requested by the Secretary that is necessary to determine whether to approve or disapprove the compact or amendment. If a compact includes revenue sharing, a market analysis or similar documentation as required by § 293.24.

§ 293.9 Where should a compact or amendment or other requests under this part be submitted for review and approval?

Submit compacts, amendments, and all other requests under 25 CFR part 293 to the Director, Office of Indian Gaming, U.S. Department of the Interior, 1849 C Street NW, Mail Stop 3543, Main Interior Building, Washington, DC 20240. If this address changes, a document with the new address will be sent for publication in the **Federal Register** within 5 business days. Compacts and amendments may also be submitted electronically to *IndianGaming@bia.gov* as long as the original copy is submitted to the address listed in this section.

Subpart C—Secretarial Review of Tribal-State Gaming Compacts

§ 293.10 How long will the Secretary take to review a compact or amendment?

(a) The Secretary must approve or disapprove a compact or amendment within 45 calendar days after receiving the compact or amendment.

(b) The Secretary will notify the Tribe and the State in writing of the decision to approve or disapprove a compact or amendment.

§ 293.11 When will the 45-day timeline begin?

The 45-day timeline will begin when a compact or amendment is received, and date stamped by the Office of Indian Gaming. The Department will provide an email acknowledgement to the Tribe and the State of receipt including the 45th day for electronically submitted compacts or amendments.

§ 293.12 What happens if the Secretary does not act on the compact or amendment within the 45-day review period?

If the Secretary does not take action to approve or disapprove a compact or amendment within the 45-day review period, the compact or amendment is approved by operation of law, but only to the extent the compact or amendment is consistent with the provisions of IGRA. The Secretary will issue a letter informing the parties that the compact or amendment has been approved by operation of law after the 45th day and before the 90th day. The Secretary's letter may include guidance to the parties identifying certain provisions that are inconsistent with the Department's interpretation of IGRA. The compact or amendment that is approved by operation of law becomes effective only upon publication in the **Federal Register**.

§ 293.13 Who can withdraw a compact or amendment after it has been received by the Secretary?

To withdraw a compact or amendment after it has been received by the Secretary, the Tribe and the State must both submit a written request to the Director, Office of Indian Gaming at the address listed in § 293.9.

§ 293.14 When does a compact or amendment take effect?

(a) A compact or amendment, that is affirmatively approved or approved by operation of law takes effect on the date that notice of its approval is published in the **Federal Register**.

(b) The notice of affirmative approval or approval by operation of law must be published in the **Federal Register** within 90 days from the date the compact or amendment is received by the Office of Indian Gaming.

§ 293.15 Is the Secretary required to disapprove a compact or amendment that violates IGRA?

No. The IGRA provides the Secretary with time limited authority to review a compact or amendment and discretionary disapproval authority. If the Secretary does not take action to approve or disapprove a compact or amendment within 45 days, IGRA provides it shall be considered to have been approved by the Secretary, but only to the extent the compact or amendment is consistent with IGRA.

§ 293.16 When may the Secretary disapprove a compact or amendment?

The Secretary may disapprove a compact or amendment only if:

(a) It violates:

(1) Any provision of IGRA;

(2) Any other provision of Federal law that does not relate to jurisdiction over gaming on Indian lands;

(3) The trust obligations of the United States to Indians; or

(b) If the documents required in § 293.8 are not submitted and the Department has informed the parties in writing of the missing documents.

Subpart D—Scope of Tribal-State Gaming Compacts

§ 293.17 May a compact or amendment include provisions addressing the application of the Tribe's or the State's criminal and civil laws and regulations?

Yes. A compact or amendment may include provisions addressing the application of the criminal and civil laws and regulations of the Tribe or the State that are directly related to, and necessary for, the licensing and regulation of the gaming activity. At the request of the Secretary pursuant to § 293.8(e), the parties must show that these laws and regulations are both directly related to and necessary for, the licensing and regulation of the gaming activity.

§ 293.18 May a compact or amendment include provisions addressing the allocation of criminal and civil jurisdiction between the State and the Tribe?

Yes. A compact or amendment may include provisions allocating criminal and civil jurisdiction between the State and the Tribe necessary for the enforcement of the laws and regulations described in § 293.17.

§ 293.19 May a compact or amendment include provisions addressing the State's costs for regulating gaming activities?

Yes. If the compact or amendment includes a negotiated allocation of jurisdiction to the State for the regulation of the gaming activity, the compact or amendment may include provisions to defray the State's actual and reasonable costs for regulating the specific Tribe's gaming activity. If the compact does not include requirements for the State to show actual and reasonable annual expenses for regulating the specific Tribe's gaming activity over the life of the compact is considered evidence of a violation of IGRA.

§ 293.20 May a compact or amendment include provisions addressing the Tribe's taxation of gaming?

Yes. A compact or amendment may include provisions addressing the Tribe's taxation of the tribally licensed gaming activity in amounts comparable to the State's taxation of State licensed gaming activities. A compact may not include provisions addressing the Tribe's taxation of other activities that may occur within or near the Tribe's gaming facility. The inclusion of provisions addressing the Tribe's taxation of other activities is considered evidence of a violation of IGRA.

§ 293.21 May a compact or amendment include provisions addressing the resolution of disputes for breach of the compact?

Yes. A compact or amendment may include provisions addressing how the parties will resolve a breach of the compact or other disputes arising from the compact including mutual limited waivers of sovereign immunity. If a Tribe is concerned that an agreement or other document, including but not limited to any dispute resolution, settlement agreement, or arbitration decision, constitutes a compact or amendment, or if the Tribe is concerned that the agreement or other document interprets the Tribe's compact or amendment to govern matters that are not directly related to the operation of gaming activities, the Tribe may submit the document to the Department as set forth in § 293.4. The inclusion of provisions addressing dispute resolution in a manner that seeks to avoid the Secretary's review is considered evidence of a violation of IGRA.

§ 293.22 May a compact or amendment include provisions addressing standards for the operation of gaming activity and maintenance of the gaming facility?

Yes. A compact or amendment may include provisions addressing the Tribe's standards for the operation of the gaming activity as well as the Tribe's standards for the maintenance of the gaming facility, including licensing. If a compact or amendment mandate that the Tribe adopt standards equivalent or comparable to the standards set forth in a State law or regulation, the parties must show that these mandated Tribal standards are both directly related to and necessary for, the licensing and regulation of the gaming activity.

§ 293.23 May a compact or amendment include provisions that are directly related to the operation of gaming activities?

Yes. A compact or amendment may include provisions that are directly related to the operation of gaming activities.

§ 293.24 What factors will be used to determine whether provisions in a compact or amendment are directly related to the operation of gaming activities?

(a) The parties must show that these provisions described in § 293.23 are directly connected to Tribe's conduct of class III gaming activities. Examples include, but are not limited to:

(1) Minimum age for patrons to participate in gaming;

(2) Transportation of gaming devices and equipment; or

(3) Exclusion of Patrons.

(b) Mutually beneficial proximity, or even co-management alone is insufficient to establish a "direct connection" between the Tribe's class III gaming and adjacent business or amenities. Additionally, Tribal infrastructure projects or economic development activities that are funded by gaming revenue and may service or otherwise provide a benefit to the gaming activity are not directly related to the conduct of gaming without other evidence of a direct connection.

(c) Provisions which are not directly related to the operation of gaming activities include, but are not limited to:

(1) Limiting third party Tribes' rights to conduct gaming;

(2) Treaty rights;

(3) Tobacco sales;

(4) Compliance with or adoption of State environmental regulation of projects or activities that are not directly related to the Tribe's operation of gaming activities and maintenance of the gaming facility;

(5) Requiring memorandum of understanding, intergovernmental agreements, or similar agreements with local governments;

(6) Enforcement of State court orders garnishing employee wages or patron winnings;

(7) Granting State court jurisdiction over tort claims arising from the Tribe's conduct of class III gaming activities;

(8) Non-gaming Tribal economic activities including activities in or adjacent to the gaming facility, including but not limited to, restaurants, nightclubs, hotels, event centers, water parks, gas stations, and convenience stores; or

(9) Tribal class I or class II gaming activities.

(d) The inclusion of provisions which the parties cannot show a direct connection to the Tribe's conduct of class III gaming activities is considered evidence of a violation of IGRA.

§ 293.25 What factors will the Secretary analyze to determine if revenue sharing is lawful?

(a) A compact or amendment may include provisions that address revenue sharing in exchange for a State's meaningful concessions resulting in a substantial economic benefit for the Tribe.

(b) The Department reviews revenue sharing provisions with great scrutiny.

We begin with the presumption that a Tribe's payment to a State or local government for anything beyond § 293.19 regulatory fees are a prohibited ''tax, fee, charge, or other assessment.'' In order for the Department to approve revenue sharing the parties must show through documentation, such as a market study or other similar evidence, that:

(1) The Tribe has requested, and the State has offered specific meaningful concessions the State was otherwise not required to negotiate;

(2) The value of the specific meaningful concessions offered by the State provides substantial economic benefits to the Tribe in a manner justifying the revenue sharing required by the compact; and

(3) The Tribe is the primary beneficiary of the gaming, measured by projected revenue to the Tribe against projected revenue shared with the State;

(c) The inclusion of revenue sharing provisions to the State that is not justified by meaningful concessions of substantial economic benefit to the Tribe is considered evidence of a violation of IGRA.

§ 293.26 May a compact or extension include provisions that limit the duration of the compact?

Yes. However, IGRA anticipates compacts are long-term agreements between a Tribe and a State. These agreements reflect carefully negotiated compromises between sovereigns. A refusal to negotiate a long-term compact, or a short-term extension of at least one year to allow for negotiations to continue, is considered evidence of a violation of IGRA.

§ 293.27 May a compact or amendment permit a Tribe to engage in any form of class III gaming activity?

Yes. If the State allows any form of class III gaming, then the State is regulating all forms of class III gaming. A State's refusal to negotiate in a compact over all forms of class III gaming, not prohibited in the State, is considered evidence of a violation of IGRA.

§ 293.28 May any other contract outside of a compact regulate Indian gaming?

No. Any contract or other agreement between a Tribe and a State or its political subdivisions which seeks to regulate a Tribe's right to conduct gaming—as limited by IGRA—is a gaming compact that must comply with IGRA and be submitted for review and approval by the Secretary. A Tribe may submit any agreement between the Tribe and the State or its political subdivisions, mandated or required by a compact or amendment, which includes provisions for the payment from a Tribe's gaming revenue or restricts or regulates a Tribe's use and enjoyment of its Indian Lands, including a Tribe's conduct of gaming, for a determination if the agreement is a compact or amendment under § 293.4(c).

§ 293.29 May a compact or amendment include provisions addressing Statewide remote wagering or internet gaming?

Yes. A compact or amendment consistent with § 293.17 may include provisions addressing Statewide remote wagering or internet gaming that is directly related to the operation of gaming activity on Indian lands. A compact may specifically include provisions allocating State and Tribal jurisdiction over remote wagering or internet gaming originating outside Indian lands where:

(a) State law and/or the compact or amendment deem the gaming to take place, for the purposes of State and Tribal law, on the Tribe's Indian lands where the server accepting the wagers is located;

(b) The Tribe regulates the gaming; and

(c) The player initiating the wager is not located on another Tribe's Indian lands.

§ 293.30 What effect does this part have on pending requests, final agency decisions already issued, and future requests?

(a) Compacts and amendments pending on [EFFECTIVE DATE OF FINAL RULE], will continue to be processed under 25 CFR part 293, promulgated on December 5, 2008, and revised June 4, 2020, unless the applicant requests in writing to proceed under this part. Upon receipt of such a request, the Secretary shall process the pending compact or amendment under this part.

(b) This part does not alter final agency decisions made pursuant to this part before [EFFECTIVE DATE OF FINAL RULE].

(c) All compacts and amendments submitted after [EFFECTIVE DATE OF FINAL RULE] will be processed under this part.

§ 293.31 How does the Paperwork Reduction Act affect this part?

The information collection requirements contained in this part have been approved by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995, 44 U.S.C. 3507(d), and assigned control number 1076–0172. A Federal agency 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.

Bryan Newland,

Assistant Secretary—Indian Affairs.

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LIST OF PUBLIC LAWS

This is a continuing list of public bills from the current session of Congress which have become Federal laws. This list is also available online at *https://www.archives.gov/federal-register/laws/current.html*.

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H.R. 8454/P.L. 117–215

Medical Marijuana and Cannabidiol Research Expansion Act (Dec. 2, 2022; 136 Stat. 2257)

H.J. Res. 100/P.L. 117–216

To provide for a resolution with respect to the unresolved disputes between certain railroads represented by the National Carriers' Conference Committee of the National Railway Labor Conference and certain of their employees. (Dec. 2, 2022; 136 Stat. 2267)

S. 3826/P.L. 117–217

To designate the facility of the United States Postal Service located at 1304 4th Avenue in Canyon, Texas, as the ''Gary James Fletcher Post Office Building''. (Dec. 2, 2022; 136 Stat. 2269)

S. 3884/P.L. 117–218

To designate the facility of the United States Postal Service located at 404 U.S. Highway 41 North in Baraga, Michigan, as the ''Cora Reynolds Anderson Post Office''. (Dec. 2, 2022; 136 Stat. 2270)

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