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Rules and Regulations

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This section of the FEDERAL REGISTER contains regulatory documents having general applicability and legal effect, most of which are keyed to and codified in the Code of Federal Regulations, which is published under 50 titles pursuant to 44 U.S.C. 1510.

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FARM CREDIT ADMINISTRATION

12 CFR Parts 611, 620, and 630

RIN 3052–AD00

Organization; Disclosure to Shareholders; Disclosure to Investors in System-Wide and Consolidated Bank Debt Obligations of the Farm Credit System; Advisory Vote

AGENCY: Farm Credit Administration.

ACTION: Final rule.

SUMMARY: The Farm Credit Administration (FCA) adopts as final without change an interim final rule which amended FCA regulations to remove the requirement that Farm Credit System (System) banks and associations hold non-binding, advisory votes on senior officer compensation in certain circumstances.

DATES: *Effective Date:* June 18, 2014.

FOR FURTHER INFORMATION CONTACT:
Deborah Wilson, Associate Director, Office of Regulatory Policy, Farm Credit Administration, McLean, VA 22102–5090, (703) 883–4224, TTY (703) 883–4056,
or
Laura McFarland, Senior Counsel, Office of General Counsel, Farm Credit Administration, McLean, VA 22102–5090, (703) 883–4020, TTY (703) 883–4056.

SUPPLEMENTARY INFORMATION: On March 31, 2014, the FCA published the interim final rule (79 FR 17854) removing the FCA regulatory requirement that (1) associations hold non-binding advisory votes on senior officer compensation when 5 percent of the voting stockholders petition for the vote, and (2) Farm Credit banks and associations hold non-binding advisory votes on senior officer compensation if senior officer compensation increased by 15 percent or more from the previous reporting period (hereafter referred to as ''advisory voting rule'').[1] The interim final rule responded to the provisions of Title VI of the Consolidated Appropriations Act, 2014 (Appropriations Act)[2] and the ''Findings by Congress'' in section 5404 of the Agricultural Act of 2014 (Farm Bill).[3] In adopting the interim final rule, the FCA explained the Appropriations Act provided that no funds available to the FCA during the current fiscal year may be used to ''implement or enforce'' the advisory voting rule and the Farm Bill directed the FCA to review its rules to ensure they reflect Congressional intent that a primary responsibility of the boards of directors of System institutions is to oversee compensation practices.

The FCA received two comments on the interim final rule. In its comment letter, the Farm Credit Council (Council), on behalf of its System members, supported the FCA deleting the non-binding, advisory vote provisions in response to the actions taken by Congress in both the Appropriations Act and the Farm Bill. In its comment letter, the Independent Community Bankers of America (ICBA) expressed the view that the FCA did not need to remove the advisory vote provisions in order to comply with recent Congressional action and suggested that FCA modify the rule through a re-proposal. The ICBA asserted that neither the Appropriations Act nor the Farm Bill require the FCA to withdraw the advisory vote provisions and that a re-proposal would pose no compliance conflict. The ICBA comment letter also mentioned several times the need to allow non-binding, advisory votes at System institutions.

After careful consideration of the comments, the FCA has determined that no changes to the interim final rule are warranted. FCA believes that further notice and comment rulemaking on this subject would be neither practical nor meaningful based on the aforementioned Congressional actions. We note, however, in response to the commenter that advisory votes are not prohibited by this rule. System institutions may employ advisory votes of shareholders on a variety of topics.

Therefore, the FCA adopts as a final rule the interim final rule, which removed from parts 611, 620, and 630 the requirement for advisory voting. Specifically, the following non-binding advisory voting provisions are withdrawn:

- § 611.100(a), defining the term ''advisory vote'';
- § 611.360, requiring policies and procedures for non-binding, advisory votes on senior officer compensation;
- § 611.410, addressing non-binding, advisory votes on senior officer compensation;
- § 620.5(a)(11), requiring disclosure of any advisory votes held during the reporting year at the institution;
- § 620.6(c)(6), requiring disclosure (adjacent to the compensation table) in the annual report of a stockholder's right to petition for a non-binding, advisory vote on senior officer compensation; and
- § 630.20(i) (last sentence), requiring disclosure of any advisory votes held during the reporting year within the System.

All other regulatory provisions and changes resulting from the October 3, 2012 (77 FR 60582) rulemaking remain in effect. In addition, the interim final rule and this action close the rulemaking petition filed by the Council on December 4, 2012.[4]

Regulatory Flexibility Act

Pursuant to section 605(b) of the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), the FCA hereby certifies that this final rule will not have a significant economic impact on a substantial number of small entities. Each of the banks in the System, considered together with its affiliated associations, has assets and annual income in excess of the amounts that would qualify them as small entities. Therefore, System institutions are not ''small entities'' as defined in the Regulatory Flexibility Act.

[1] *See* 77 FR 60582 (10/03/2012). The rule was effective December 17, 2012, but non-binding, advisory votes on compensation increases of 15 percent or more were not required until 2015 (77 FR 76215, December 27, 2012).

[2] 113 Public Law 76, 128 Stat. 5 (H.R. 3547), signed by the President on January 17, 2014.

[3] 113 Public Law 79, 128 Stat. 649 (H.R. 2642), signed by the President on February 7, 2014.

[4] On December 4, 2012, the Council, on behalf of the System banks and associations, filed a petition requesting that the FCA repeal the advisory voting rule. Interested parties have the right to petition a Federal agency to issue, amend, or repeal regulations under 5 U.S.C. 553(e). The FCA published the petition in the **Federal Register** on February 19, 2013 (78 FR 11551), and invited comments.

List of Subjects

12 CFR Part 611

Agriculture, Banks, banking, Rural areas.

12 CFR Part 620

Accounting, Agriculture, Banks, banking, Reporting and recordkeeping requirements, Rural areas.

12 CFR Part 630

Accounting, Agriculture, Banks, banking, Organization and functions (Government agencies), Reporting and recordkeeping requirements, Rural areas.

Accordingly, the interim rule amending 12 CFR parts 611, 620, and 630, which was published on March 31, 2014 (79 FR 17854), is adopted as a final rule without changes.

Dated: June 12, 2014.

Dale L. Aultman,

Secretary, Farm Credit Administration Board.

[FR Doc. 2014–14227 Filed 6–17–14; 8:45 am]

BILLING CODE 6705–01–P

BUREAU OF CONSUMER FINANCIAL PROTECTION

12 CFR Part 1081

[Docket No.: CFPB–2013–0030]

RIN 3170–AA29

Rules of Practice for Issuance of Temporary Cease-and-Desist Orders

AGENCY: Bureau of Consumer Financial Protection.

ACTION: Final rule.

SUMMARY: On September 26, 2013, 78 FR 59163, the Consumer Financial Protection Bureau (Bureau) published in the **Federal Register** an interim final rule establishing procedures for the issuance of a temporary cease-and-desist order (TCDO) pursuant to section 1053(c) of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), which requires the Bureau to prescribe rules establishing procedures for the conduct of adjudication proceedings. After reviewing and considering the single public comment offered on its interim final rule, the Bureau adopts the interim final rule without change.

DATES: This final rule takes effect on July 18, 2014.

FOR FURTHER INFORMATION CONTACT: John R. Coleman, Senior Counsel, Legal Division, Consumer Financial Protection Bureau, 1700 G Street NW., Washington, DC 20552; at (202) 435–7254.

SUPPLEMENTARY INFORMATION:

I. Background

On June 29, 2012, the Bureau published in the **Federal Register** the final Rules of Practice for Adjudication Proceedings pursuant to sections 1022(b)(1) and 1053(e) of the Dodd-Frank Act, 12 U.S.C. 5512(b)(1) & 5563(e).[1] That final rule, however, does not apply to the issuance of a TCDO pursuant to section 1053(c) of the Dodd-Frank Act.[2] The Bureau previously invited comments as to whether special rules governing such proceedings are necessary and, if so, what the rules should provide.[3] One commenter recommended that the Bureau promulgate rules governing temporary cease-and-desist proceedings initiated pursuant to section 1053(c) of the Dodd-Frank Act and pointed to the Federal Deposit Insurance Corporation's (FDIC) rules governing temporary cease-and-desist proceedings, 12 CFR 308.131, as an example of such rules.[4]

On September 26, 2013, 78 FR 59163, the Bureau published its interim final rule establishing procedures for the issuance of a temporary cease-and-desist order (TCDO) pursuant to section 1053(c) of the Dodd-Frank Act. In developing the interim final rule, the Bureau considered the procedures related to temporary cease-and-desist orders that are followed by other regulatory agencies, including the FDIC, the Securities and Exchange Commission, and the Office of the Comptroller of the Currency. The interim final rule most closely follows the FDIC's approach as codified in 12 CFR 308.131. The Bureau issued the interim final rule to clarify (1) the basis for the issuance of a TCDO; (2) the content, scope, and form of a TCDO; (3) the procedures governing the issuance of a TCDO and the remedies available to the Bureau in issuing a TCDO; and (4) the rights of persons subject to a TCDO.

The interim final rule described each section of the rule and explained the basis of the rule with reference to rules of other agencies as appropriate. After reviewing and considering the single public comment offered, the Bureau adopts the interim final rule without change.

II. Legal Authority

The Bureau promulgates this final rule pursuant to its authority to implement section 1053 of the Dodd-Frank Act, 12 U.S.C. 5563(e), as well as its general rulemaking authority to promulgate rules necessary or appropriate to carry out the Federal consumer financial laws, 12 U.S.C. 5512(b)(1).

III. Public Comment on the Interim Final Rule

In response to the interim final rule, the Bureau received one comment letter that did not contain any specific comments or suggestions pertaining to the interim final rule. Accordingly, the Bureau is adopting the interim final rule without change.

IV. Section 1022(b) Provisions

In developing the interim final and final rules, the Bureau has considered the potential benefits, costs, and impacts and has consulted or offered to consult with the prudential regulators, the Department of Housing and Urban Development, and the Federal Trade Commission, including with regard to consistency with any prudential, market, or systemic objectives administered by such agencies.[5]

The Dodd-Frank Act requires the Bureau to prescribe rules establishing such procedures as may be necessary to carry out section 1053 of the Act, which provides for temporary cease-and-orders in subsection (c). The final rule itself does not impose significant costs upon covered persons, but, consistent with section 1053, provides a straightforward and efficient process for the issuance of a temporary cease-and-desist order, and a direct route to judicial review.

The final rule has no unique impact on insured depository institutions or insured credit unions with $10 billion or less in assets described in section 1026(a) of the Dodd-Frank Act, nor does it have a unique impact on rural consumers.

V. Regulatory Requirements

As the Bureau noted in publishing the interim final rule, this rule relates solely

[1] *See* 77 FR 39058 (June 29, 2012) (codified at 12 CFR Part 1081).

[2] *Id.* at 39058.

[3] *See* 76 FR 45338, 45338 (July 28, 2011).

[4] *See* 77 FR 39058, 39060 (June 29, 2012).

[5] Section 1022(b)(2)(A) of the Dodd-Frank Act calls for the Bureau to consider the potential benefits and costs of a regulation to consumers and covered persons, including the potential reduction of access by consumers to consumer financial products or services; the impact on depository institutions and credit unions with $10 billion or less in total assets as described in section 1026 of the Dodd-Frank Act; and the impact on consumers in rural areas. Section 1022(b)(2)(B) directs the Bureau to consult with the appropriate prudential regulators or other Federal agencies regarding consistency with objectives those agencies administer. The manner and extent to which these provisions apply to a rulemaking of this kind, which establishes Bureau procedures and imposes no standards of conduct, is unclear. Nevertheless, to inform this rulemaking more fully, the Bureau performed the analyses and consultations described in those provisions of the Dodd-Frank Act.

to agency procedure and practice and, thus, is not subject to the notice and comment requirements of the Administrative Procedure Act, 5 U.S.C. 553(b). Because no notice of proposed rulemaking is required, these regulations are not a ''rule'' as defined by the Regulatory Flexibility Act, 5 U.S.C. 601(2), and no initial or final regulatory flexibility analysis is required.

VI. Paperwork Reduction Act

The Bureau has determined that the regulations in this subpart do not impose any new recordkeeping, reporting, or disclosure requirements on covered entities or members of the public that would constitute collections of information requiring approval under the Paperwork Reduction Act, 44 U.S.C. 3501 et seq.

List of Subjects in 12 CFR Part 1081

Administrative practice and procedure, Banking, Banks, Consumer protection, Credit, Credit unions, Law enforcement, National banks, Savings associations, Trade practices.

Authority and Issuance

For the reasons set forth above, the interim final rule amending 12 CFR part 1081 published at 78 FR 59163, September 26, 2013, is adopted as a final rule without change.

Dated: June_10, 2014.

Richard Cordray,

Director, Bureau of Consumer Financial Protection.

[FR Doc. 2014–14228 Filed 6–17–14; 8:45 am]

BILLING CODE 4810–AM–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 872

[Docket No. FDA–2012–N–0677]

Dental Devices; Reclassification of Blade-Form Endosseous Dental Implant

AGENCY: Food and Drug Administration, HHS.

ACTION: Final order.

SUMMARY: The Food and Drug Administration (FDA) is issuing a final order to reclassify the blade-form endosseous dental implant, a preamendments class III device, into class II (special controls). On its own initiative, based on new information, FDA is revising the classification of blade-form endosseous dental implants.

DATES: This order is effective July 18, 2014.

FOR FURTHER INFORMATION CONTACT: Michael J. Ryan, Center for Devices and Radiological Health, 10903 New Hampshire Ave., Bldg. 66, Rm. 1615, Silver Spring, MD 20993, 301–796–6283, *michael.ryan@fda.hhs.gov*.

SUPPLEMENTARY INFORMATION:

I. Background—Regulatory Authorities

The Federal Food, Drug, and Cosmetic Act (the FD&C Act), as amended by the Medical Device Amendments of 1976 (the 1976 amendments) (Pub. L. 94–295), the Safe Medical Devices Act of 1990 (Pub. L. 101–629), the Food and Drug Administration Modernization Act of 1997 (FDAMA) (Pub. L. 105–115), the Medical Device User Fee and Modernization Act of 2002 (Pub. L. 107–250), the Medical Devices Technical Corrections Act (Pub. L. 108–214), the Food and Drug Administration Amendments Act of 2007 (Pub. L. 110–85), and the Food and Drug Administration Safety and Innovation Act (FDASIA) (Pub. L. 112–144), among other amendments, established a comprehensive system for the regulation of medical devices intended for human use. Section 513 of the FD&C Act (21 U.S.C. 360c) established three categories (classes) of devices, reflecting the regulatory controls needed to provide reasonable assurance of their safety and effectiveness. The three categories of devices are class I (general controls), class II (special controls), and class III (premarket approval).

Under section 513(d) of the FD&C Act, devices that were in commercial distribution before the enactment of the 1976 amendments, May 28, 1976 (generally referred to as preamendments devices), are classified after FDA has: (1) Received a recommendation from a device classification panel (an FDA advisory committee); (2) published the panel's recommendation for comment, along with a proposed regulation classifying the device; and (3) published a final regulation classifying the device. FDA has classified most preamendments devices under these procedures.

Devices that were not in commercial distribution prior to May 28, 1976 (generally referred to as postamendments devices), are automatically classified by section 513(f) of the FD&C Act into class III without any FDA rulemaking process. Those devices remain in class III and require premarket approval unless, and until, the device is reclassified into class I or II or FDA issues an order finding the device to be substantially equivalent, in accordance with section 513(i) of the FD&C Act, to a predicate device that does not require premarket approval. The Agency determines whether new devices are substantially equivalent to predicate devices by means of premarket notification procedures in section 510(k) of the FD&C Act (21 U.S.C. 360(k)) and 21 CFR part 807.

A preamendments device that has been classified into class III may be marketed by means of premarket notification procedures (510(k) process) without submission of a premarket approval application (PMA) until FDA issues a final order under section 515(b) of the FD&C Act (21 U.S.C. 360e(b)) requiring premarket approval or until the device is subsequently reclassified into class I or class II.

On July 9, 2012, FDASIA was enacted. Section 608(a) of FDASIA amended section 513(e) of the FD&C Act, changing the mechanism for reclassifying a device from rulemaking to an administrative order.

Section 513(e) of the FD&C Act governs reclassification of classified preamendments devices. This section provides that FDA may, by administrative order, reclassify a device based upon ''new information.'' FDA can initiate a reclassification under section 513(e) of the FD&C Act or an interested person may petition FDA to reclassify a preamendments device. The term ''new information,'' as used in section 513(e) of the FD&C Act, includes information developed as a result of a reevaluation of the data before the Agency when the device was originally classified, as well as information not presented, not available, or not developed at that time. (See, e.g., *Holland-Rantos Co.* v. *United States Department of Health, Education, and Welfare,* 587 F.2d 1173, 1174 n.1 (D.C. Cir. 1978); *Upjohn* v. *Finch,* 422 F.2d 944 (6th Cir. 1970); *Bell* v. *Goddard,* 366 F.2d 177 (7th Cir. 1966).)

Reevaluation of the data previously before the Agency is an appropriate basis for subsequent action where the reevaluation is made in light of newly available authority (see *Bell,* 366 F.2d at 181; *Ethicon, Inc.* v. *FDA,* 762 F.Supp. 382, 388–391 (D.D.C. 1991)) or in light of changes in ''medical science'' (*Upjohn,* 422 F.2d at 951). Whether data before the Agency are old or new data, the ''new information'' to support reclassification under section 513(e) of the FD&C Act must be ''valid scientific evidence,'' as defined in section 513(a)(3) and 21 CFR 860.7(c)(2). (See, e.g., *General Medical Co.* v. *FDA,* 770 F.2d 214 (D.C. Cir. 1985); *Contact Lens Manufacturers Association* v. *FDA,* 766

F.2d 592 (D.C. Cir. 1985), cert. denied, 474 U.S. 1062 (1986).)

FDA relies upon ''valid scientific evidence'' in the classification process to determine the level of regulation for devices. To be considered in the reclassification process, the ''valid scientific evidence'' upon which the Agency relies must be publicly available. Publicly available information excludes trade secret and/or confidential commercial information, e.g., the contents of a pending PMA. See section 520(c) of the FD&C Act (21 U.S.C. 360j(c)). Section 520(h)(4) of the FD&C Act, added by FDAMA, provides that FDA may use, for reclassification of a device, certain information in a PMA 6 years after the application has been approved. This includes information from clinical and preclinical tests or studies that demonstrate the safety or effectiveness of the device but does not include descriptions of methods of manufacture or product composition and other trade secrets.

Section 513(e)(1) of the FD&C Act sets forth the process for issuing a final order. Specifically, prior to the issuance of a final order reclassifying a device, the following must occur: (1) Publication of a proposed order in the **Federal Register**; (2) a meeting of a device classification panel described in section 513(b) of the FD&C Act; and (3) consideration of comments to a public docket.

II. Regulatory History of the Device

FDA published a proposed order to reclassify this device in the **Federal Register** of January 14, 2013 (78 FR 2647) (the ''proposed order''). As discussed in the proposed order, the Agency originally issued a final rule classifying all endosseous dental implants (without distinguishing based on geometry) into class III (52 FR 30082, August 12, 1987). After later consideration by a reclassification panel, root-form endosseous dental implants were reclassified into class II in a final rule issued on May 12, 2004 (69 FR 26302), but blade-form endosseous dental implants remained in class III.

After consideration of available information on blade-form endosseous dental implants, the proposed order indicated that FDA believed these devices could also be down classified to class II, subject to the identified special controls. As required by section 513(e)(1) of the FD&C Act, on July 18, 2013, FDA also convened a meeting of the Dental Products Panel (the Panel) to consider the existing valid scientific evidence to support reclassification of blade-form endosseous dental implants into class II.

The Panel discussed and agreed that the risks to health for this device were adequately captured as presented by FDA. The Panel deliberations included discussion of whether the risk of bone loss is higher for blade-form dental implants as compared to root-form dental implant devices. The Panel also discussed the technique-sensitive nature of this device and expressed a concern that additional training, which may not be found in the current curriculum for dental schools, is needed prior to the use of this device to address the identified risks to health.

The Panel agreed that the proposed special controls were reasonable to mitigate the identified risks to health but recommended the device labeling include specific patient selection criteria and recommendations for training and education requirements for clinicians using this device. The Panel recommended that companies marketing this device ensure that device-specific training is available to clinicians. The Panel also recommended clinical data as a special control for the purpose of capturing failure rates and adverse event detection.

The special controls as previously proposed by FDA included documented clinical experience for effective use and observed adverse events which addresses the recommendations for patient selection criteria, and failure rate and adverse event detection. Additionally, the special controls include patient labeling which must contain instructions for reporting complications. The patient labeling will also address the concern for failure rate and adverse event detection. To address the Panel's concern related to recommendations for training and education requirements, FDA has added a special control for the device labeling to include qualifications and training requirements for clinicians using this device.

The Panel concluded that general controls alone are not sufficient due to the identified risks to health; however, special controls, in combination with the general controls, can be sufficient to assure the safety and effectiveness of blade-form endosseous dental implants. The Panel agreed that this device should be reclassified into class II (special controls).

III. Public Comments in Response to the Proposed Order

In response to the proposed order, FDA received two comments from practicing clinicians. Both of the comments supported reclassification of the devices into class II, and described positive clinical experience regarding the safety and effectiveness of the device. FDA agrees with the comments.

IV. The Final Order

Under section 513(e) of the FD&C Act, FDA is adopting its findings as published in the preamble to the proposed order. FDA is issuing this final order to reclassify the blade-form endosseous dental implant from class III to class II and to establish special controls. Following the effective date of this final order, firms marketing blade-form endosseous dental implants will need either to: (1) Comply with the particular mitigation measures set forth in the special controls or (2) use alternative mitigation measures, but demonstrate to the Agency's satisfaction that those alternative measures identified by the firm will provide at least an equivalent assurance of safety and effectiveness.

Section 510(m) of the FD&C Act provides that FDA may exempt a class II device from the premarket notification requirements under section 510(k) of the FD&C Act if FDA determines that premarket notification is not necessary to provide reasonable assurance of the safety and effectiveness of the devices. FDA has determined that premarket notification is necessary to provide reasonable assurance of safety and effectiveness of blade-form endosseous implants; and therefore, this device type is not exempt from premarket notification requirements.

V. Environmental Impact

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

VI. Paperwork Reduction Act of 1995

This final order establishes special controls that refer to previously approved collections of information found in other FDA regulations. These collections of information are subject to review by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520). The collections of information in 21 CFR part 812 have been approved under OMB control number 0910–0078; the collections of information in 21 CFR part 807, subpart E, have been approved under OMB control number 0910–0120; the collections of information in 21 CFR part 814, subpart B, have been approved under OMB control number 0910–0231;

and the collections of information under 21 CFR part 801 have been approved under OMB control number 0910–0485.

VII. Codification of Orders

Prior to the amendments by FDASIA, section 513(e) of the FD&C Act provided for FDA to issue regulations to reclassify devices. Although section 513(e) of the FD&C Act as amended requires FDA to issue final orders rather than regulations, FDASIA also provides for FDA to revoke previously issued regulations by order. FDA will continue to codify classifications and reclassifications in the Code of Federal Regulations (CFR). Changes resulting from final orders will appear in the CFR as changes to codified classification determinations or as newly codified orders. Therefore, under section 513(e)(1)(A)(i) of the FD&C Act, as amended by FDASIA, in this final order, we are revoking the requirements in 21 CFR 872.3640 related to the classification of blade-form endosseous implants as class III devices and codifying the reclassification of blade-form endosseous into class II.

List of Subjects in 21 CFR Part 872

Medical devices.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs, 21 CFR part 872 is amended as follows:

PART 872—DENTAL DEVICES

■ 1. The authority citation for 21 CFR part 872 continues to read as follows:

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

■ 2. Section 872.3640 is amended by revising paragraph (a) and (b)(2) to read as follows:

§ 872.3640 Endosseous dental implant.

(a) *Identification.* An endosseous dental implant is a prescription device made of a material such as titanium or titanium alloy that is intended to be surgically placed in the bone of the upper or lower jaw arches to provide support for prosthetic devices, such as artificial teeth, in order to restore a patient's chewing function.

(b) * * *

(2) *Classification.* Class II (special controls). The device is classified as class II if it is a blade-form endosseous dental implant. The special controls for this device are:

(i) The design characteristics of the device must ensure that the geometry and material composition are consistent with the intended use;

(ii) Mechanical performance (fatigue) testing under simulated physiological conditions to demonstrate maximum load (endurance limit) when the device is subjected to compressive and shear loads;

(iii) Corrosion testing under simulated physiological conditions to demonstrate corrosion potential of each metal or alloy, couple potential for an assembled dissimilar metal implant system, and corrosion rate for an assembled dissimilar metal implant system;

(iv) The device must be demonstrated to be biocompatible;

(v) Sterility testing must demonstrate the sterility of the device;

(vi) Performance testing to evaluate the compatibility of the device in a magnetic resonance (MR) environment;

(vii) Labeling must include a clear description of the technological features, how the device should be used in patients, detailed surgical protocol and restoration procedures, relevant precautions and warnings based on the clinical use of the device, and qualifications and training requirements for device users including technicians and clinicians;

(viii) Patient labeling must contain a description of how the device works, how the device is placed, how the patient needs to care for the implant, possible adverse events and how to report any complications; and

(ix) Documented clinical experience must demonstrate safe and effective use and capture any adverse events observed during clinical use.

Dated: June 12, 2014.

Leslie Kux,

Assistant Commissioner for Policy.

[FR Doc. 2014–14216 Filed 6–17–14; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 301

[TD 9669]

RIN 1545–BM25

Participation of a Person Described in Section 6103(n) in a Summons Interview Under Section 7602(a)(2) of the Internal Revenue Code

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Temporary regulations.

SUMMARY: This document contains temporary regulations modifying regulations promulgated under section 7602(a) of the Internal Revenue Code relating to administrative summonses. Specifically, these temporary regulations clarify that persons with whom the IRS or the Office of Chief Counsel (Chief Counsel) contracts for services described in section 6103(n) and its implementing regulations may be included as persons designated to receive summoned books, papers, records, or other data and to take summoned testimony under oath. These temporary regulations may affect taxpayers, a taxpayer's officers or employees, and any third party who is served with a summons, as well as any other person entitled to notice of a summons. The text of these temporary regulations serves as the text of the proposed regulations (REG–121542–14) set forth in the notice of proposed rulemaking on this subject in the Proposed Rules section in this issue of the **Federal Register**.

DATES: *Effective Date:* These regulations are effective on June 18, 2014.

Applicability Date: For date of applicability, see paragraph (d) of this temporary regulation.

FOR FURTHER INFORMATION CONTACT: A M Gulas at (202) 317–6834 (not a toll-free number).

SUPPLEMENTARY INFORMATION:

Background and Explanation of Provisions

These temporary regulations amend Procedure and Administration Regulations (26 CFR part 301) promulgated under section 7602 of the Internal Revenue Code. These temporary regulations make clear that persons described in section 6103(n) and Treas. Reg. § 301.6103(n)–1(a) with whom the IRS or Chief Counsel contracts for services may receive books, papers, records, or other data summoned by the IRS and take testimony of a person who the IRS has summoned as a witness to provide testimony under oath. While IRS officers and employees remain responsible for issuing summonses and developing and conducting examinations, the temporary regulations clarify that contractors are permitted to participate fully in a summons interview. Full participation includes, but is not limited to, receipt, review, and use of summoned books, papers, records, or other data, being present during summons interviews, questioning the person providing testimony under oath, and asking a summoned person's representative to clarify an objection or an assertion of privilege.

The assistance of persons from outside the IRS or Chief Counsel promotes efficient administration and enforcement of laws administered by the IRS, by providing specialized knowledge, skills, or abilities that the IRS officers or employees assigned to the case may not possess. For example, outside persons often assist the IRS in matters involving transfer pricing. To clarify the role of these outside persons, these temporary regulations expressly provide that when an IRS officer or employee summons a taxpayer or other witness to produce books, papers, records, or other data and/or to give testimony, an outside person hired by the IRS or Chief Counsel authorized to receive returns or return information pursuant to section 6103(n) may receive the summoned books, papers, records, or other data and take the testimony of the witness under oath.

When the IRS hires an outside person to assist an IRS officer or employee to review books and papers, analyze data, or take testimony from a summoned witness, the IRS will ensure that the inherently governmental functions associated with section 7602, for example, deciding whether to issue a summons, deciding whom to summon, what information must be produced or who will be required to testify, and issuing the summons, will still be performed by an IRS officer or employee. The contractors' role will be limited to functions that are not inherently governmental, such as taking testimony by asking questions, reviewing books or papers, or analyzing other data. As a further safeguard, the temporary regulations expressly provide that any contractor that the IRS authorizes to ask questions of a summoned witness testifying under oath must do so in the presence and under the guidance of an IRS officer or employee.

The conclusion that contractors may receive summoned books and papers, analyze data, and question summoned witnesses is consistent with Treas. Reg. § 301.7602–2(c)(1)(i)(B) and (c)(1)(ii) *Example* 2. Under those rules, which implement the provision requiring notice to the taxpayer of contacts by IRS officers or employees with third parties, contractors (in this case appraisers) are treated in the same manner as IRS officers or employees when they contact industry experts to discuss a taxpayer's business.

The temporary regulations are effective for summons interviews conducted on or after June 18, 2014. The applicability of the temporary regulations will expire on June 16, 2017.

Special Analyses

It has been determined that this Treasury Decision is not a significant regulatory action as defined in Executive Order 12866, as supplemented by Executive Order 13563. Therefore, a regulatory assessment is not required. The IRS has determined that sections 553(b) and (d) of the Administrative Procedure Act (5 U.S.C. chapter 5) do not apply to these regulations and because the regulations do not impose a collection of information on small entities, the Regulatory Flexibility Act (5 U.S.C. chapter 6) does not apply. Pursuant to section 7805(f) of the Internal Revenue Code, the IRS will submit these temporary regulations to the Chief Counsel for Advocacy of the Small Business Administration for comments about the regulations' impact on small business.

Drafting Information

The principal author of these regulations is A M Gulas of the Office of Associate Chief Counsel (Procedure and Administration).

List of Subjects in 26 CFR Part 301

Employment taxes, Estate taxes, Excise taxes, Gift taxes, Income taxes, Penalties, Reporting and recordkeeping requirements.

Adoption of Amendments to the Regulations

Accordingly, 26 CFR part 301 is amended as follows:

PART 301—PROCEDURE AND ADMINISTRATION

■ **Paragraph 1.**

The authority citation for part 301 continues to read in part as follows:

Authority: 26 U.S.C. 7805 * * *

■ **Par. 2.** Section 301.7602–1T is added to read as follows:

§ 301.7602–1T Examination of books and witnesses (temporary).

(a) [Reserved]. For further guidance, see § 301.7602–1(a).

(b) through (b)(2) [Reserved]. For further guidance, see § 301.7602–1(b) through (b)(2).

(b)(3) *Participation of a person described in section 6103(n).* For purposes of this paragraph (b), a person authorized to receive returns or return information under section 6103(n) and § 301.6103(n)–1(a) of the regulations may receive and examine books, papers, records, or other data produced in compliance with the summons and, in the presence and under the guidance of an IRS officer or employee, participate fully in the interview of the witness summoned by the IRS to provide testimony under oath. Fully participating in an interview includes, but is not limited to, receipt, review, and use of summoned books, papers, records, or other data; being present during summons interviews; questioning the person providing testimony under oath; and asking a summoned person's representative to clarify an objection or assertion of privilege.

(c) [Reserved]. For further guidance, see § 301.7602–1(c).

(d) *Effective/applicability date.* This section applies to summons interviews conducted on or after June 18, 2014.

(e) *Expiration date.* The applicability of this section expires on or before June 16, 2017.

Heather C. Maloy,

Acting Deputy Commissioner for Services and Enforcement.

Approved: June 9, 2014

Mark J. Mazur,

Assistant Secretary of the Treasury (Tax Policy).

[FR Doc. 2014–14265 Filed 6–17–14; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket No. USCG–2013–0214]

Safety Zones; Recurring Events in Captain of the Port Duluth Zone—Point to LaPointe Swim

AGENCY: Coast Guard, DHS.

ACTION: Notice of enforcement of regulation.

SUMMARY: The Coast Guard will enforce the safety zone in 33 CFR 165.943 for the Point to LaPointe Swim in LaPointe, WI from 7:20 a.m. through 10 a.m. on August 2, 2014. This action is necessary to protect participants and spectators during the Point to LaPointe swim. During the enforcement period, entry into, transiting, or anchoring within the safety zone is prohibited unless authorized by the Captain of the Port Duluth or his designated on-scene representative.

DATES: The regulations in 33 CFR 165.943(b) will be enforced from 7:20 a.m. through 10 a.m. on August 2, 2014, for the Point to LaPointe Swim safety zone, § 165.943(a)(7).

FOR FURTHER INFORMATION CONTACT: If you have questions on this document, call or email LT Judson Coleman, Chief of Waterways Management, Coast Guard; telephone (218) 725–3818, email *Judson.A.Coleman@uscg.mil*.

SUPPLEMENTARY INFORMATION: The Coast Guard will enforce the safety zone for the annual Point to LaPointe Swim in 33 CFR 165.943(a)(7) from 7:20 a.m. through 10 a.m. on August 2, 2014 on all waters between Bayfield, WI and Madeline Island, WI within an imaginary line created by the following coordinates: 46°48′50.97″ N, 090°48′44.28″ W, moving southeast to 46°46′44.90″ N, 090°47′33.21″ W, then moving northeast to 46°46′52.51″ N, 090°47′17.14″ W, then moving northwest to 46°49′03.23″ N, 090°48′25.12″ W and finally running back to the starting point.

Entry into, transiting, or anchoring within the safety zone is prohibited unless authorized by the Captain of the Port Duluth or his designated on-scene representative. The Captain of the Port's designated on-scene representative may be contacted via VHF Channel 16.

This document is issued under authority of 33 CFR 165.943 and 5 U.S.C. 552(a). In addition to this publication in the **Federal Register**, the Coast Guard will provide the maritime community with advance notification of the enforcement of this safety zone via Broadcast Notice to Mariners. The Captain of the Port Duluth or his on-scene representative may be contacted via VHF Channel 16.

Dated: June 4, 2014.

A.H. Moore, Jr.,

Commander, U.S. Coast Guard, Captain of the Port Duluth.

[FR Doc. 2014–14236 Filed 6–17–14; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket No. USCG–2014–0061]

RIN 1625–AA00

Safety Zones; Annually Recurring Events in Coast Guard Southeastern New England Captain of the Port Zone

AGENCY: Coast Guard, DHS.

ACTION: Final rule.

SUMMARY: The Coast Guard is amending the safety zones for the ''RI Air National Guard Air Show'' and the ''Swim Buzzards Bay'' events. This amendment adds an additional month to the eligible dates for which the Safety Zones apply to each of these two events.

DATES: This rule is effective July 18, 2014.

ADDRESSES: Documents mentioned in this preamble are part of docket USCG–2014–0061. To view documents mentioned in the preamble as being available in the docket, go to *http://www.regulations.gov*, type the docket number in the ''SEARCH'' box and click ''SEARCH.'' Click on Open Docket Folder on the line associated with this rulemaking. You may also visit the Docket Management Facility in Room W12–140 on the ground floor of the Department of Transportation West Building, 1200 New Jersey Avenue SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call Mr. Edward G. LeBlanc at Coast Guard Sector Southeastern New England, 401–435–2351. If you have questions on viewing the docket, please call Renee V. Wright, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION:

Table of Acronyms

DHS Department of Homeland Security
FR Federal Register
NPRM Notice of Rulemaking

A. Regulatory History and Information

On April 8, 2014, we published a notice of rulemaking (NPRM) entitled ''Safety Zones; Annually Recurring Events in Coast Guard Southeastern New England Captain of the Port Zone'' in the **Federal Register** (79 FR 19302). We received no comments on the rule.

B. Basis and Purpose

The legal basis for this rule is 33 U.S.C. 1231, 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; Public Law 107–295, 116 Stat. 2064; and Department of Homeland Security Delegation No. 0170.1, which collectively authorize the Coast Guard to define safety zones.

On May 22, 2012, the Coast Guard published a Final Rule in the **Federal Register** (77 FR 30188–30194) that amended certain established permanent safety zones for numerous recurring marine events within Coast Guard Sector Southeastern New England. For each recurring marine event a range of eligible dates is included in the Table to 33 CFR 165.173. The Coast Guard is amending the safety zones at section 6.2 (RI Air National Guard Air Show) and 7.12 (Swim Buzzards Bay) of the Table contained in 33 CFR 165.173. This amendment adds an additional month to the eligible dates for which the safety zones at 33 CFR 165.173 apply to each of these two events.

C. Background

For the Air Show, the month of May is added to June and July, so that the safety zone at 33 CFR 165.173 now applies to one weekend in May, June, or July, rather than just June or July as was applicable under the original regulation being amended.

For the Swim, the month of June is added to July and August, so that the safety zone at 33 CFR 165.173 applies to one Saturday or Sunday in June, July, or August, rather than just July or August as was applicable under the original regulation being amended.

These revisions provide a larger window of eligible dates for the sponsors of each event to better coordinate with other waterway users, major participants, and state and local safety officials.

D. Discussion of Comments, Changes and the Final Rule

No comments were received, and no changes were made to the language contained in the NPRM.

E. Regulatory Analyses

We developed this rule after considering numerous statutes and executive orders related to rulemaking. Below we summarize our analyses based on these statutes and executive orders.

1. Regulatory Planning and Review

This rule is not a significant regulatory action under section 3(f) of Executive Order 12866, Regulatory Planning and Review, as supplemented by Executive Order 13563, and does not require an assessment of potential costs and benefits under section 6(a)(3) of that Order. The Office of Management and Budget has not reviewed it under that Order.

We expect the economic impact of this rule to be so minimal that a full Regulatory Evaluation is unnecessary. Although this regulation may have some impact on the public, the potential impact will be minimized for the following reasons: The Air Show will be limited to only a single three-day weekend period (Friday, Saturday, and Sunday) potentially in the month of May, and the Air Show has occurred annually for many years with no negative public comments or concerns regarding impacts to navigation. The Swim will be limited to only a single

Saturday or Sunday potentially in the month of June, and the Swim has occurred annually for many years with few public concerns regarding impacts to navigation, and those concerns have been readily and satisfactorily resolved.

Notifications are made to the local maritime community through the Local Notice to Mariners well in advance of the Air Show and Swim. No new or additional restrictions are imposed on vessel traffic.

2. Impact on Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we have considered whether this rule will 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 received no comments from the Small Business Administration on this rule.

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. This rule affects the following entities, some of which might be small entities: owners or operators of vessels intending to transit, fish, or anchor in the area of the Air Show as listed in section 6.2 of the Table to 33 CFR 165.173.

The rule will not have a significant economic impact on a substantial number of small entities for the following reasons: The Air Show is limited to only a single three-day weekend period (Friday, Saturday, and Sunday) during the entire eligible period (May, June, July), and the Air Show has occurred annually for many years with no negative public concerns regarding impacts to navigation. The Swim is limited to a single Saturday or Sunday during the entire eligible period (June, July, August), and the Swim has occurred annually for many years with few negative public concerns regarding impacts to navigation, and those concerns have been readily and satisfactorily resolved.

Notifications are made to the local maritime community through the Local Notice to Mariners well in advance of the Air Show and Swim. No new or additional restrictions are imposed on vessel traffic.

3. Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), in the NPRM we offered to assist small entities in understanding this rule so that they can better evaluate its effects on them and participate in the rulemaking process.

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

4. Collection of Information

This rule calls for no new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

5. Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has a substantial direct effect on State or local governments and would either preempt State law or impose a substantial direct cost of compliance on them. We have analyzed this rule under that Order and have determined that it does not have implications for federalism.

6. Protest Activities

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

7. Unfunded Mandates Reform Act

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

8. Taking of Private Property

This rule will 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.

9. Civil Justice Reform

This 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.

10. Protection of Children From Environmental Health Risks

We have analyzed this rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This 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.

11. Indian Tribal Governments

This rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

12. Energy Effects

This rule is not a ''significant energy action'' under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.

13. Technical Standards

This rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

14. Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4370f), and have concluded this action appears to be one of a category of actions which do not individually or cumulatively have a significant effect on the human environment.

Any comments made in response to the previously published Notice of Proposed Rulemaking for this action

were also considered in arriving at this conclusion. This rule is categorically excluded, under figure 2–1, paragraphs (34)(g) and (34)(h) of the Instruction since it involves establishment of safety zones for annually recurring marine events, including marine related fireworks events and special local regulations for regattas. An environmental analysis checklist and a categorical exclusion determination are available in the docket where indicated under **ADDRESSES**.

List of Subjects in 33 CFR Part 165

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

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

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

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

Authority: 33 U.S.C. 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

§ 165.173 [Amended]

■ 2. Amend the table in § 165.173 as follows:

■ a. Add a new category entitled ''5.0 MAY'' below the category ''1.0 365 DAY JANUARY–DECEMBER'' and above the category ''6.0 JUNE'';

■ b. Redesignate item 6.2, ''RI National Guard Air Show'' as item 5.1, and locate it beneath the category ''5.0 MAY'';

■ c. Redesignate item 7.12 ''Swim Buzzards Bay'' as item 6.2, and locate it below item 6.1 ''Oak Bluffs Summer Solstice'', and reserve item 7.12;

■ d. Revise the entry for ''Date'' in newly redesignated item 5.1, ''RI Air National Guard Air Show'' to read ''Date: One weekend (Friday, Saturday, and Sunday) in May, June, or July, as announced in the local Notice to Mariners.''; and

■ e. Revise the entry for ''Date'' in newly redesignated item 6.2 ''Swim Buzzards Bay'' to read ''Date: One Saturday or Sunday in June, July, or August, as announced in the local Notice to Mariners.''

Dated: May 21, 2014.

J.T. Kondratowicz,

Captain, U.S. Coast Guard, Captain of the Port Southeastern New England.

[FR Doc. 2014–14238 Filed 6–17–14; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2013–0673; FRL–9911–08]

Pyroxasulfone; Pesticide Tolerances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation amends tolerances for residues of pyroxasulfone in or on corn, field, forage and corn, field, grain. K–I Chemical U.S.A. Inc. c/o Landis International, Inc. requested these amended tolerances under the Federal Food, Drug, and Cosmetic Act (FFDCA).

DATES: This regulation is effective June 18, 2014. Objections and requests for hearings must be received on or before August 18, 2014, and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: The docket for this action, identified by docket identification (ID) number EPA–HQ–OPP–2013–0673, is available at *http://www.regulations.gov* or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW., Washington, DC 20460–0001. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OPP Docket is (703) 305–5805. Please review the visitor instructions and additional information about the docket available at *http://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: Lois Rossi, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001; main telephone number: (703) 305–7090; email address: *RDFRNotices@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this Action apply to me?

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

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

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

You may access a frequently updated electronic version of EPA's tolerance regulations at 40 CFR part 180 through the Government Printing Office's e-CFR site at *http://www.ecfr.gov/cgi-bin/text-idx?&c=ecfr&tpl=/ecfrbrowse/Title40/40tab_02.tpl.*

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

Under FFDCA section 408(g), 21 U.S.C. 346a, any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA–HQ–OPP–2013–0673 in the subject line on the first page of your submission. All objections and requests for a hearing must be in writing, and must be received by the Hearing Clerk on or before August 18, 2014. Addresses for mail and hand delivery of objections and hearing requests are provided in 40 CFR 178.25(b).

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing (excluding any Confidential Business Information (CBI)) for inclusion in the public docket. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit the non-CBI copy of your objection or hearing request, identified by docket ID number EPA–HQ–OPP–2013–0673, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be CBI or other information whose disclosure is restricted by statute.
- *Mail:* OPP Docket, Environmental Protection Agency Docket Center (EPA/DC), (28221T), 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001.

• *Hand Delivery:* To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at *http://www.epa.gov/dockets/contacts.html.*

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

II. Summary of Petitioned-for Tolerance

In the **Federal Register** of October 25, 2013 (78 FR 63938) (FRL–9901–96), EPA issued a document pursuant to FFDCA section 408(d)(3), 21 U.S.C. 346a(d)(3), announcing the filing of a pesticide petition (PP 3F8196) by K–I Chemical U.S.A. Inc. c/o Landis International, Inc., P.O. Box 5126, Valdosta, GA 31603–5126. The petition requested that 40 CFR 180.659 be amended by increasing the tolerance for residues of the herbicide, pyroxasulfone, [3-[[[5-(difluoromethoxy)-1-methyl-3-(trifluoromethyl)-1H-pyrazol-4-yl]methyl]sulfonyl]-4,5-dihydro-5,5-dimethylisoxazole] and its metabolite 5-difluoromethoxy-1-methyl-3-trifluoromethyl-1 *H*-pyrazol-4-carboxylic acid (M3) calculated as the stoichiometric equivalent of pyroxasulfone, in or on corn, field, grain from 0.015 to 0.02 parts per million (ppm); and also increasing the tolerance for residues of pyroxasulfone, [3-[[[5-(difluoromethoxy)-1-methyl-3-(trifluoromethyl)-1H-pyrazol-4-yl]methyl]sulfonyl]-4,5-dihydro-5,5-dimethylisoxazole] and its metabolites 5-difluoromethoxy-1-methyl-3-trifluoromethyl-1 *H*-pyrazol-4-ylmethanesulfonic acid (M1), 5-difluoromethoxy-1-methyl-3-trifluoromethyl-1 *H*-pyrazol-4-carboxylic acid (M3), and 5-difluoromethoxy-3-trifluoromethyl-1 *H*-pyrazol-4-yl) methanesulfonic acid (M25) calculated as the stoichiometric equivalent of pyroxasulfone in or on corn, field, forage from 0.06 to 0.09 ppm. The amended tolerances were sought to cover residues that may be found on corn following use of pyroxasulfone with an adjuvant. That document referenced a summary of the petition prepared by K–I Chemical U.S.A. Inc. c/o Landis International, Inc., the registrant, which is available in the docket, *http://www.regulations.gov.* There were no comments received in response to the notice of filing.

III. Aggregate Risk Assessment and Determination of Safety

Section 408(b)(2)(A)(i) of FFDCA allows EPA to establish a tolerance (the legal limit for a pesticide chemical residue in or on a food) only if EPA determines that the tolerance is ''safe.'' Section 408(b)(2)(A)(ii) of FFDCA defines ''safe'' to mean that ''there is a reasonable certainty that no harm will result from aggregate exposure to the pesticide chemical residue, including all anticipated dietary exposures and all other exposures for which there is reliable information.'' This includes exposure through drinking water and in residential settings, but does not include occupational exposure. Section 408(b)(2)(C) of FFDCA requires EPA to give special consideration to exposure of infants and children to the pesticide chemical residue in establishing a tolerance and to ''ensure that there is a reasonable certainty that no harm will result to infants and children from aggregate exposure to the pesticide chemical residue. . . .''

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

A. Toxicological Profile

In the **Federal Register** of July 31, 2013 (78 FR 46274) (FRL–9393–6), EPA published a final rule (2013 rulemaking) establishing certain tolerances for residues of the herbicide pyroxasulfone and its metabolites based on EPA's conclusion that aggregate exposure to pyroxasulfone is safe for the general population, including infants and children. Since the 2013 rulemaking, there have been no additional tolerance actions for pyroxasulfone, nor has the toxicity profile for pyroxasulfone changed. Specific information on the studies reviewed for that rulemaking and the nature of the adverse effects caused by pyroxasulfone, as well as the no-observed-adverse-effect-level (NOAEL) and the lowest-observed-adverse-effect-level (LOAEL) from the toxicity studies are discussed in the 2013 rulemaking which can be found in docket ID number EPA–HQ–OPP–2012–0439.

B. Toxicological Points of Departure/ Levels of Concern

Once a pesticide's toxicological profile is determined, EPA identifies toxicological points of departure (POD) and levels of concern to use in evaluating the risk posed by human exposure to the pesticide. For hazards that have a threshold below which there is no appreciable risk, the toxicological POD is used as the basis for derivation of reference values for risk assessment. PODs are developed based on a careful analysis of the doses in each toxicological study to determine the dose at which no adverse effects are observed (the NOAEL) and the lowest dose at which adverse effects of concern are identified (the LOAEL). Uncertainty/safety factors are used in conjunction with the POD to calculate a safe exposure level—generally referred to as a population-adjusted dose (PAD) or a reference dose (RfD)—and a safe margin of exposure (MOE). For non-threshold risks, the Agency assumes that any amount of exposure will lead to some degree of risk. Thus, the Agency estimates risk in terms of the probability of an occurrence of the adverse effect expected in a lifetime. For more information on the general principles EPA uses in risk characterization and a complete description of the risk assessment process, see *http://www.epa.gov/pesticides/factsheets/riskassess.htm.* A summary of the toxicological endpoints for pyroxasulfone used for human risk assessment is also discussed in Unit III.B of the final rule published in the **Federal Register** of February 29, 2012 (77 FR 12207) (FRL–9334–2).

C. Exposure Assessment

1. *Dietary exposure from food and feed uses.* In evaluating dietary exposure to pyroxasulfone, EPA conducted a new dietary exposure and risk assessment that considered exposure under the petitioned-for tolerances as well as all existing pyroxasulfone tolerances in 40 CFR 180.659. EPA assessed dietary exposures from pyroxasulfone in food as follows:

i. *Acute exposure.* Quantitative acute dietary exposure and risk assessments are performed for a food-use pesticide, if a toxicological study has indicated the possibility of an effect of concern occurring as a result of a 1-day or single exposure. Such effects were identified for pyroxasulfone. In estimating acute dietary exposure, EPA used food consumption information from the United States Department of Agriculture's (USDA) *National Health and Nutrition Examination Survey, What We Eat in America,* (NHANES/WWEIA). As to residue levels in food, EPA assumed 100 percent crop treated (PCT) at tolerance-level residues adjusted upward to account for metabolites which are not in the

tolerance expression from specific use patterns.

ii. *Chronic exposure.* In conducting the chronic dietary exposure assessment EPA used the food consumption data from the USDA/NHANES/WWEIA. As to residue levels in food, EPA made the same assumptions (adjusted tolerance-level residues and 100 PCT) as in the acute dietary exposure assessment.

iii. *Cancer.* EPA determines whether quantitative cancer exposure and risk assessments are appropriate for a food-use pesticide based on the weight of the evidence from cancer studies and other relevant data. Cancer risk is quantified using a linear or nonlinear approach. If sufficient information on the carcinogenic mode of action is available, a threshold or nonlinear approach is used and a cancer RfD is calculated based on an earlier noncancer key event. If carcinogenic mode of action data are not available, or if the mode of action data determines a mutagenic mode of action, a default linear cancer slope factor approach is utilized. EPA has concluded that a nonlinear RfD approach is appropriate for assessing cancer risk to pyroxasulfone. Cancer risk was assessed using the same exposure estimates as discussed in Unit III.C.1.ii.

iv. *Anticipated residue and percent crop treated (PCT) information.* EPA did not use anticipated residue and/or PCT information in the dietary assessment for pyroxasulfone. Adjusted tolerance level residues and/or 100 PCT were assumed for all food commodities.

2. *Dietary exposure from drinking water.* The Agency used screening level water exposure models in the dietary exposure analysis and risk assessment for pyroxasulfone in drinking water. These simulation models take into account data on the physical, chemical, and fate/transport characteristics of pyroxasulfone. Further information regarding EPA drinking water models used in pesticide exposure assessment can be found at *http://www.epa.gov/oppefed1/models/water/index.htm.*

Based on the Pesticide Root Zone Model/Exposure Analysis Modeling System (PRZM/EXAMS) and Pesticide Root Zone Model Ground Water (PRZM GW), the estimated drinking water concentrations (EDWCs) of pyroxasulfone for acute exposures are estimated to be 17 parts per billion (ppb) for surface water and 210 ppb for ground water. EDWCs of pyroxasulfone for chronic exposures for non-cancer assessments are estimated to be 3.2 ppb for surface water and 174 ppb for ground water.

Modeled estimates of drinking water concentrations were directly entered into the dietary exposure model. For acute dietary risk assessment, the water concentration value of 210 ppb was used to assess the contribution to drinking water. For chronic dietary risk assessment, the water concentration of value 174 ppb was used to assess the contribution to drinking water.

3. *From non-dietary exposure.* The term ''residential exposure'' is used in this document to refer to non-occupational, non-dietary exposure (e.g., for lawn and garden pest control, indoor pest control, termiticides, and flea and tick control on pets). Pyroxasulfone is not registered for any specific use patterns that would result in residential exposure.

4. *Cumulative effects from substances with a common mechanism of toxicity.* Section 408(b)(2)(D)(v) of FFDCA requires that, when considering whether to establish, modify, or revoke a tolerance, the Agency consider ''available information'' concerning the cumulative effects of a particular pesticide's residues and ''other substances that have a common mechanism of toxicity.'' EPA has not found pyroxasulfone to share a common mechanism of toxicity with any other substances, and pyroxasulfone does not appear to produce a toxic metabolite produced by other substances. For the purposes of this tolerance action, therefore, EPA has assumed that pyroxasulfone does not have a common mechanism of toxicity with other substances. For information regarding EPA's efforts to determine which chemicals have a common mechanism of toxicity and to evaluate the cumulative effects of such chemicals, see EPA's Web site at *http://www.epa.gov/pesticides/cumulative.*

D. Safety Factor for Infants and Children

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

2. *Prenatal and postnatal sensitivity.* The prenatal and postnatal toxicity database for pyroxasulfone includes developmental toxicity studies in rats and rabbits, a DNT study in rats, and a 2-generation reproduction toxicity study in rats. As discussed in the 2013 rulemaking, evidence of increased susceptibility of fetuses and offspring was seen in the DNT study and developmental toxicity study in rabbits following *in utero* or post-natal exposure to pyroxasulfone. No increased susceptibility was seen in the rat developmental or reproduction toxicity studies. In rabbits, developmental toxicity was only seen at the limit dose of 1,000 milligrams/kilogram/day (mg/kg/day) as reduced fetal weight and increased fetal resorptions with a NOAEL of 500 mg/kg/day for these effects, compared to no maternal toxicity at these doses. In a DNT study in rats, offspring toxicity (decreased brain weight and morphometric changes on PND 21) was seen at 300 mg/kg/day compared to no maternal toxicity at 900 mg/kg/day. The degree of concern for the increased susceptibility seen in these studies is low and there are no residual uncertainties based on the following considerations:

i. The increased susceptibility is occurring at high doses.

ii. NOAELs and LOAELs have been identified for all effects of concern, and thus a clear dose response has been well defined.

iii. The PODs selected for risk assessment are protective of the fetal/offspring effects.

3. *Conclusion.* EPA has determined that reliable data show the safety of infants and children would be adequately protected if the FQPA SF were reduced to 1X. That decision is based on the following findings:

i. The toxicity database for pyroxasulfone is complete.

ii. Pyroxasulfone is a neurotoxic chemical and there is evidence of increased susceptibility of offspring with regard to neurotoxic effects in the rat DNT study. There is also evidence of increased susceptibility of fetuses/offspring with regard to non-neurotoxic effects in the rabbit developmental toxicity study. However, concern for the increased susceptibility is low for the reasons stated in Unit III.D.2.; therefore, EPA determined that a 10X FQPA SF is not necessary to protect infants and children.

iii. There are no residual uncertainties identified in the exposure databases. The dietary food exposure assessments were performed based on 100 PCT and adjusted tolerance-level residues. EPA made conservative (protective) assumptions in the ground and surface

water modeling used to assess exposure to pyroxasulfone in drinking water. These assessments will not underestimate the exposure and risks posed by pyroxasulfone.

E. Aggregate Risks and Determination of Safety

EPA determines whether acute and chronic dietary pesticide exposures are safe by comparing aggregate exposure estimates to the acute PAD (aPAD) and chronic PAD (cPAD). For linear cancer risks, EPA calculates the lifetime probability of acquiring cancer given the estimated aggregate exposure. Short-, intermediate-, and chronic-term risks are evaluated by comparing the estimated aggregate food, water, and residential exposure to the appropriate PODs to ensure that an adequate MOE exists.

1. *Acute risk.* Using the exposure assumptions discussed in this unit for acute exposure, the acute dietary exposure from food and water to pyroxasulfone will occupy 3.6% of the aPAD for all infants (<1 year old), the population group receiving the greatest exposure.

2. *Chronic risk.* Using the exposure assumptions described in this unit for chronic exposure, EPA has concluded that chronic exposure to pyroxasulfone from food and water will utilize 48% of the cPAD for all infants (<1 year old) the population group receiving the greatest exposure. There are no residential uses for pyroxasulfone.

3. *Short- and intermediate-term risk.* Short- and intermediate-term aggregate exposure takes into account short- and intermediate-term residential exposure plus chronic exposure to food and water (considered to be a background exposure level). Short- and intermediate-term adverse effects were identified; however, pyroxasulfone is not registered for any use patterns that would result in short- or intermediate-term residential exposure. Because there is no short- or intermediate-term residential exposure and chronic dietary exposure has already been assessed under the appropriately protective cPAD (which is at least as protective as the POD used to assess short- and intermediate-term risk), no further assessment of short- or intermediate-term risk is necessary, and EPA relies on the chronic dietary risk assessment for evaluating short- and intermediate-term risk for pyroxasulfone.

4. *Aggregate cancer risk for U.S. population.* The Agency has determined that the quantification of risk using a non-linear (i.e., RfD) approach will adequately account for all chronic toxicity, including carcinogenicity, that could result from exposure to pyroxasulfone. Therefore, based on the results of the chronic risk assessment discussed in Unit III.E.2., pyroxasulfone is not expected to pose a cancer risk to humans.

5. *Determination of safety.* Based on these risk assessments, EPA concludes that there is a reasonable certainty that no harm will result to the general population, or to infants and children from aggregate exposure to pyroxasulfone residues.

IV. Other Considerations

A. Analytical Enforcement Methodology

Adequate enforcement methodology (a liquid chromatography/mass spectrometry/mass spectrometry (LC/MS/MS) method) is available to enforce the tolerance expression. The method may be requested from: Chief, Analytical Chemistry Branch, Environmental Science Center, 701 Mapes Rd., Ft. Meade, MD 20755–5350; telephone number: (410) 305–2905; email address: *residuemethods@epa.gov.*

B. International Residue Limits

In making its tolerance decisions, EPA seeks to harmonize U.S. tolerances with international standards whenever possible, consistent with U.S. food safety standards and agricultural practices. EPA considers the international maximum residue limits (MRLs) established by the Codex Alimentarius Commission (Codex), as required by FFDCA section 408(b)(4). The Codex Alimentarius is a joint United Nations Food and Agriculture Organization/World Health Organization food standards program, and it is recognized as an international food safety standards-setting organization in trade agreements to which the United States is a party. EPA may establish a tolerance that is different from a Codex MRL; however, FFDCA section 408(b)(4) requires that EPA explain the reasons for departing from the Codex level. The Codex has not established a MRL for pyroxasulfone.

V. Conclusion

Therefore, tolerances are established for residues of pyroxasulfone, [3-[[[5-(difluoromethoxy)-1-methyl-3-(trifluoromethyl)-1H-pyrazol-4-yl]methyl]sulfonyl]-4,5-dihydro-5,5-dimethylisoxazole], including its metabolites and degradates, as set forth in the regulatory text.

VI. Statutory and Executive Order Reviews

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

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

This final rule directly regulates growers, food processors, food handlers, and food retailers, not States or tribes, nor does this action alter the relationships or distribution of power and responsibilities established by Congress in the preemption provisions of FFDCA section 408(n)(4). As such, the Agency has determined that this action will not have a substantial direct effect on States or tribal governments, on the relationship between the national government and the States or tribal governments, or on the distribution of power and responsibilities among the various levels of government or between the Federal Government and Indian tribes. Thus, the Agency has determined that Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999) and Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000) do not apply to this final rule. In addition, this final rule does not impose any enforceable duty or contain any unfunded mandate as described under Title II of the Unfunded Mandates Reform Act of 1995 (UMRA) (2 U.S.C. 1501 *et seq.*).

This action does not involve any technical standards that would require

Agency consideration of voluntary consensus standards pursuant to section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA) (15 U.S.C. 272 note).

VII. Congressional Review Act

Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*), EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 180

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

Dated: June 12, 2014.

Lois Rossi,

Director, Registration Division, Office of Pesticide Programs.

Therefore, 40 CFR chapter I is amended as follows:

PART 180—[AMENDED]

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

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

■ 2. Section 180.659 is amended by:

■ a. Revising the commodity ''Corn, field, grain'' in the table in paragraph (a)(1) and;

■ b. Revising the commodity ''Corn field, forage'' in the table in paragraph (a)(2) to read as follows:

§ 180.659 Pyroxasulfone; tolerances for residues.

(a) *General.* (1) * * *

Commodity	Parts per million
Corn, field, grain	0.02
* * * * *	

(2) * * *

Commodity	Parts per million
Corn, field, forage	0.09
* * * * *	

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[FR Doc. 2014–14251 Filed 6–17–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 300

[EPA–HQ–SFUND–1999–0013; FRL–9912–53–Region 2]

National Oil and Hazardous Substances Pollution Contingency Plan; National Priorities List: Deletion of the Federal Creosote Superfund Site

AGENCY: Environmental Protection Agency.

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) Region 2 announces the deletion of the Federal Creosote Superfund Site (Site) located in the Borough of Manville, New Jersey, from the National Priorities List (NPL). The NPL, promulgated pursuant to section 105 of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980, as amended, is an appendix of the National Oil and Hazardous Substances Pollution Contingency Plan (NCP). The EPA and the State of New Jersey, through the New Jersey Department of Environmental Protection, have determined that all appropriate response actions under CERCLA, other than long-term groundwater monitoring, and five-year reviews, have been completed. However, this deletion does not preclude future actions under Superfund.

DATES: This action is effective June 18, 2014.

ADDRESSES: Submit your comments, identified by Docket ID no. EPA–HQ–SFUND–1999–0013, by one of the following methods:

- *http://www.regulations.gov.* Follow on-line instructions for submitting comments.
- *Email: puvogel.rich@epa.gov:* Rich Puvogel, Remedial Project Manager; *seppi.pat@epa.gov:* Pat Seppi, Community Involvement Coordinator.
- *Fax:* (212) 637–4429.
- *Mail:*

Rich Puvogel, Remedial Project Manager, U.S. Environmental Protection Agency, Emergency & Remedial Response Division, 290 Broadway, 19th Floor, New York, NY 10007–1866;

or

Pat Seppi, Community Involvement Coordinator, U.S. Environmental Protection Agency, Public Affairs Division, 290 Broadway, 26th Floor, New York, NY 10007–1866.

- *Hand delivery:* U.S. Environmental Protection Agency, Emergency & Remedial Response Division, 290 Broadway, 19th Floor, New York, NY 10007–1866.

Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID no. EPA–HQ–SFUND–1999–0013. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov or email.* The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means 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 EPA without going through *http://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, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: EPA has established a docket for this action under Docket Identification No. EPA–HQ–SFUND–1999–0013. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, i.e., Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the site information repositories.

Locations, contacts, phone numbers and viewing hours are:

U.S. Environmental Protection Agency, Region II, Superfund Records Center, 290 Broadway, Room 1828, New York, New York 10007–1866, (212) 637–4308, Hours: 9:00 a.m. to 5:00 p.m., Monday through Friday;

and at

Manville Public Library, 100 South 10th Avenue, Manville, New Jersey 08835, (908) 722–9722, Hours: Mon. through Fri.: 10:00 a.m. to 8:00 p.m.; Fri.: 10:00 a.m. to 5:30 p.m.; Sat.: 10:00 a.m. to 5:30 p.m.

FOR FURTHER INFORMATION CONTACT: Rich Puvogel, Remedial Project Manager, U.S. Environmental Protection Agency, Region II, 290 Broadway, 19th Floor, New York, New York 10007–1866, (212) 637–4410, or email *puvogel.rich@epa.gov*.

SUPPLEMENTARY INFORMATION: The site to be deleted from the NPL is: Federal Creosote Superfund Site, Manville, New Jersey. A Notice of Intent to Delete for this Site was published in the **Federal Register** at 79 FR 12436 on March 5, 2014.

The closing date for comments on the Notice of Intent to Delete was April 4, 2014. One comment was received. The comment suggested that a process be established to protect against potential future exposures to subsurface contaminants brought to the surface by redevelopment activities. Deed notices apply adequate restrictions on properties to protect against redevelopment activities that have the potential to deposit contaminated subsurface soils on the land surface. Deed notices, a required component of the selected remedy, have been implemented at the Federal Creosote Superfund Site. The selected remedy, which adequately protects human health and the environment, has been fully implemented and therefore satisfies the deletion criteria of the National Contingency Plan.

EPA maintains the NPL as the list of sites that appear to present a significant risk to public health, welfare, or the environment. Deletion from the NPL does not preclude further remedial action. Whenever there is a significant release from a site deleted from the NPL, the deleted site may be restored to the NPL without application of the hazard ranking system. Deletion of a site from the NPL does not affect responsible party liability in the unlikely event that future conditions warrant further actions.

List of Subjects in 40 CFR Part 300

Environmental protection, Air pollution control, Chemicals, Hazardous waste, Hazardous substances, Intergovernmental relations, Penalties, Reporting and recordkeeping requirements, Superfund, Water pollution control, Water supply.

Dated: June 1, 2014.

Judith A. Enck,

Regional Administrator, Region 2.

For reasons set out in the preamble, 40 CFR part 300 is amended as follows:

PART 300—NATIONAL OIL AND HAZARDOUS SUBSTANCES POLLUTION CONTINGENCY PLAN

■ 1. The authority citation for part 300 continues to read as follows:

Authority: 33 U.S.C. 1321(c)(2); 42 U.S.C. 9601–9657; E.O. 12777, 56 FR 54757, 3 CFR, 1991 Comp., p. 351; E.O. 12580, 52 FR 2923; 3 CFR, 1987 Comp., p. 193.

Appendix B to Part 300—[Amended]

■ 2. Table 1 of Appendix B to part 300 is amended by removing the entry for ''NJ'', ''Federal Creosote'', ''Manville Borough''.

[FR Doc. 2014–14233 Filed 6–17–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 721

[EPA–HQ–OPPT–2014–0276; FRL–9910–51]

RIN 2070–AB27

Modification of Significant New Use Rules on Certain Chemical Substances; Update of Chemical Identities

AGENCY: Environmental Protection Agency (EPA).

ACTION: Direct final rule.

SUMMARY: EPA is updating the chemical identities of significant new use rules (SNURs) under the Toxic Substances Control Act (TSCA) for 36 chemical substances which were the subject of premanufacture notices (PMNs). This action updates SNURs that were issued using generic chemical names but will now identify the specific chemical name and chemical abstract number.

DATES: This rule is effective on August 18, 2014. For purposes of judicial review, this rule shall be promulgated at 1 p.m. (e.s.t.) on July 2, 2014.

Written adverse or critical comments, or notice of intent to submit adverse or critical comments, on this direct final rule must be received on or before July 18, 2014 (see Unit III. of the **SUPPLEMENTARY INFORMATION**). If EPA receives written adverse or critical comments, or notice of intent to submit adverse or critical comments, on before July 18, 2014, EPA will withdraw the relevant sections of this direct final rule before its effective date.

For additional information on related reporting requirement dates, see Units I.A. and III. of the **SUPPLEMENTARY INFORMATION**.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPPT–2014–0276, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute.
- *Mail:* Document Control Office (7407M), Office of Pollution Prevention and Toxics (OPPT), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001.
- *Hand Delivery:* To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at *http://www.epa.gov/dockets/contacts.html.*

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

FOR FURTHER INFORMATION CONTACT:

For technical information contact: Kenneth Moss, Chemical Control Division (7405M), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001; telephone number: (202) 564–9232; email address: *moss.kenneth@epa.gov.*

For general information contact: The TSCA-Hotline, ABVI-Goodwill, 422 South Clinton Ave., Rochester, NY 14620; telephone number: (202) 554–1404; email address: *TSCA-Hotline@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you manufacture, process, or use the chemical substances contained in this rule. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers

determine whether this document applies to them. Potentially affected entities may include:

• Manufacturers or processors of one or more subject chemical substances (NAICS codes 325 and 324110), e.g., chemical manufacturing and petroleum refineries.

B. What should I consider as I prepare my comments for EPA?

1. *Submitting CBI.* Do not submit this information to EPA through regulations.gov or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for preparing your comments.* When submitting comments, remember to:

i. Identify the document by docket ID number and other identifying information (subject heading, **Federal Register** date and page number).

ii. Follow directions. The Agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

iii. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

iv. Describe any assumptions and provide any technical information and/or data that you used.

v. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

vi. Provide specific examples to illustrate your concerns and suggest alternatives.

vii. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

viii. Make sure to submit your comments by the comment period deadline identified.

II. Background

A. What action is the Agency taking?

Using direct final procedures, EPA is updating the chemical identity listings SNURs for 36 chemical substances which were the subject of PMNs. The SNURs were previously issued using generic chemical names. This action identifies the specific chemical name and chemical abstract number in the modified SNUR, as this information is now publicly available. EPA is not changing the significant new use reporting requirements, the basis, or the findings for these SNURs. These SNURs will continue to require persons to notify EPA at least 90 days before commencing the manufacture or processing of a chemical substance for any activity designated by these SNURs as a significant new use. Receipt of such notices allows EPA to assess risks that may be presented by the intended uses and, if appropriate, to regulate the proposed use before it occurs.

Previously, in the **Federal Register** of July 28, 2009 (74 FR 37224) (FRL–8392–4), EPA issued a notice ''TSCA Chemical Substance Inventory Update; Changing Certain Chemical Substances Identities from Confidential to Non-Confidential.'' The notice announced that the specific chemical identities of various chemical substances, including 36 subject to the SNURs identified in this direct final rule, would be listed on the public version of the TSCA Chemical Substance Inventory.

B. What is the Agency's authority for taking this action?

Section 5(a)(2) of TSCA (15 U.S.C. 2604(a)(2)) authorizes EPA to determine that a use of a chemical substance is a ''significant new use.'' Once EPA determines that a use of a chemical substance is a significant new use, TSCA section 5(a)(1)(B) requires persons to submit a significant new use notice (SNUN) to EPA at least 90 days before they manufacture or process the chemical substance for that use. Persons who must report are described in § 721.5.

III. Direct Final Procedures

EPA is issuing these chemical identity changes as a direct final rule, as described in § 721.160(c)(3) and § 721.170(d)(4). In accordance with § 721.160(c)(3)(ii) and § 721.170(d)(4)(i)(B), the effective date of this rule is August 18, 2014 without further notice, unless EPA receives written adverse or critical comments, or notice of intent to submit adverse or critical comments before July 18, 2014.

If EPA receives written adverse or critical comments, or notice of intent to submit adverse or critical comments, on one or more of these SNURs before July 18, 2014, EPA will withdraw the relevant sections of this direct final rule before its effective date. EPA will then issue a proposed SNUR for the chemical substance(s) on which adverse or critical comments were received, providing a 30-day period for public comment.

This rule updates the chemical identity of SNURs for a number of chemical substances. Any person who submits adverse or critical comments, or notice of intent to submit adverse or critical comments, must identify the chemical substance to which it applies. EPA will not withdraw a SNUR modification for a chemical substance not identified in the comment.

IV. Statutory and Executive Order Reviews

A. Executive Order 12866

This rule modifies SNURs for several new chemical substances that were the subject of PMNs, or TSCA section 5(e) consent orders. This action does not alter any obligations under these SNURs and therefore is not a significant action under Executive Order 12866, entitled ''Regulatory Planning and Review'' (58 FR 51735, October 4, 1993).

B. Paperwork Reduction Act

According to Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), an agency may not conduct or sponsor, and a person is not required to respond to a collection of information that requires OMB approval under PRA, unless it has been approved by OMB and displays a currently valid OMB control number. The information collection requirements related to this action have already been approved by OMB pursuant to PRA under OMB control number 2070–0012 (EPA ICR No. 574). This action does not impose any burden requiring additional OMB approval.

C. Regulatory Flexibility Act (RFA)

This rule would provide more specific information on the chemical substances subject to the SNURs affected by the rule, and therefore does not have a significant economic impact on a substantial number of small entities.

D. Unfunded Mandates Reform Act (UMRA)

Based on EPA's experience with proposing and finalizing SNURs, State, local, and Tribal governments have not been impacted by these rulemakings, and EPA does not have any reasons to believe that any State, local, or Tribal government will be impacted by this rule. As such, EPA has determined that this rule does not impose any enforceable duty, contain any unfunded mandate, or otherwise have any effect on small governments subject to the

requirements of UMRA sections 202, 203, 204, or 205 (2 U.S.C. 1501 *et seq.*).

E. Executive Order 13132

This action will not have a 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, as specified in Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999).

F. Executive Order 13175

This rule does not have Tribal implications because it is not expected to have substantial direct effects on Indian Tribes. This rule does not significantly nor uniquely affect the communities of Indian Tribal governments, nor does it involve or impose any requirements that affect Indian Tribes. Accordingly, the requirements of Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), do not apply to this rule.

G. Executive Order 13045

This action is not subject to Executive Order 13045, entitled ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997), because this is not an economically significant regulatory action as defined by Executive Order 12866, and this action does not address environmental health or safety risks disproportionately affecting children.

H. Executive Order 13211

This action is not subject to Executive Order 13211, entitled ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001), because this action is not expected to affect energy supply, distribution, or use and because this action is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

In addition, since this action does not involve any technical standards, NTTAA section 12(d) (15 U.S.C. 272 note), does not apply to this action.

J. Executive Order 12898

This action does not entail special considerations of environmental justice related issues as delineated by Executive Order 12898, entitled ''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations'' (59 FR 7629, February 16, 1994).

V. Congressional Review Act

Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*), EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 721

Environmental protection, Chemicals, Hazardous substances, Reporting and recordkeeping requirements.

Dated: June 11, 2014.

Maria J. Doa,

Director, Chemical Control Division, Office of Pollution Prevention and Toxics.

Therefore, 40 CFR part 721 is amended as follows:

PART 721—[AMENDED]

■ 1. The authority citation for part 721 continues to read as follows:

Authority: 15 U.S.C. 2604, 2607, and 2625(c).

■ 2. In § 721.303, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.303 Acetic acid, 2-methoxy-, methyl ester.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as acetic acid, 2-methoxy-, methyl ester (PMN P–99–0365, CAS No. 6290–49–9) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 3. In § 721.338, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.338 Certain salts of an acrylate copolymer.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substances identified as 2-propenoic acid, polymer with 2-propenamide, ammonium salt (PMN P–00–0333; CAS No. 55554–55–7) and generically as salt of an acrylate copolymer (PMN P–00–0334) are subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 4. In § 721.530, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.530 Propanoyl chloride, 3-chloro-2,2-dimethyl-.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as propanoyl chloride, 3-chloro-2,2-dimethyl- (PMN P–84–491; CAS No. 4300–97–4) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 5. In § 721.558, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.558 2-Propanol, 1,1′-iminobis-, N-tallow alkyl derivs., hydrochlorides.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as 2-propanol, 1,1′-iminobis-, N-tallow alkyl derivs., hydrochlorides (PMN P–96–1426; CAS No. 1078715–59–9) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 6. In § 721.1568, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.1568 Benzenediazonium, 2-(methoxycarbonyl)-, chloride (1:1).

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as benzenediazonium, 2-(methoxycarbonyl)-, chloride (1:1) (PMN P–93–533; CAS No. 35358–78–2) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 7. In § 721.1625, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.1625 Benzenesulfonic acid, dodecyl-, branched, compds. with N,N-dimethyl-1,3-propanediamine (2:1).

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as benzenesulfonic acid, dodecyl-, branched, compds. with N,N-dimethyl-1,3-propanediamine (2:1) (PMN P–90–456; CAS No. 319926–68–6) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 8. In § 721.2091, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.2091 Propane, 1,1,1,3,3,3-hexachloro-.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as propane, 1,1,1,3,3,3-hexachloro- (PMN P–96–273; CAS No. 3607–78–1) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 9. In § 721.2527, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.2527 Acetamide, N-[2-[2-(2-bromo-6-cyano-4-nitrophenyl)diazenyl]-5-(diethylamino)phenyl]-.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as acetamide, N-[2-[2-(2-bromo-6-cyano-4-nitrophenyl)diazenyl]-5-(diethylamino)phenyl]- (PMN P–95–514; CAS No. 2537–62–4) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 10. In § 721.2577, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.2577 Certain copper complexes of (substituted sulfonaphthyl azo substituted phenyl) disulfonaphthyl azo, amine salt.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substances identified as cuprate(3-), [3-[2-[5-(hydroxy-.kappa.O)-4-[2-[1-(hydroxy-.kappa.O)-6-(phenylamino)-3-sulfo-2-naphthalenyl]diazenyl-.kappa.N1]-2-methylphenyl]diazenyl]-1,5-naphthalenedisulfonato(5-)]-, hydrogen, compd. with 2,2′-iminobis[ethanol] (1:3:3) (PMN P–00–0364; CAS No. 1078726–27–8) and cuprate(3-), [3-[2-[5-(hydroxy-.kappa.O)-4-[2-[1-(hydroxy-.kappa.O)-6-(phenylamino)-3-sulfo-2-naphthalenyl]diazenyl-.kappa.N1]-2-methylphenyl]diazenyl]-1,5-naphthalenedisulfonato(5-)]-, ammonium (1:3) (PMN P–00–0365; CAS No. 1078726–28–9) are subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 11. In § 721.2805, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.2805 2-Propenoic acid, 2-(phenylthio)ethyl ester.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as 2-propenoic acid, 2-(phenylthio)ethyl ester (PMN P–96–824; CAS No. 95175–38–5) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 12. In § 721.3062, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.3062 1H-Indene-2-carboxylic acid, 5-chloro-2,3-dihydro-1-oxo-, methyl ester.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as 1H-indene-2-carboxylic acid, 5-chloro-2,3-dihydro-1-oxo-, methyl ester (PMN P–00–966; CAS No. 65738–56–9) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 13. In § 721.3063, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.3063 Certain substituted phenyl azo substituted phenyl esters.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substances identified as glycine, N-[3-(acetylamino)-4-[2-(2-cyano-4-nitrophenyl)diazenyl]phenyl]-N-(2-methoxy-2-oxoethyl)-, methyl ester (PMN P–95–0655: CAS No. 149850–30–6); L-alanine, N-[5-(acetylamino)-2-chloro-4-[2-(2-cyano-4-nitrophenyl)diazenyl]phenyl]-, methyl ester (PMN P–95–0782; CAS No. 157707–95–4); and generically as substituted phenyl azo substituted phenyl esters (PMN P–95–0871) are subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 14. In § 721.3380, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.3380 Benzenamine, 4-methoxy-2-methyl-N-phenyl-.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as benzenamine, 4-methoxy-2-methyl-N-phenyl- (PMN P–83–910; CAS No. 41317–15–1) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 15. In § 721.3420, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.3420 Benzene, 1-bromo-4-methoxy-2-methyl-.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as benzene, 1-bromo-4-methoxy-2-methyl- (PMN P–83–906; CAS No. 27060–75–9) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 16. In § 721.3830, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.3830 Phenol, 2-[[[3-(dimethylamino)propyl]amino]methyl]-6-methyl-, 4-polybutene derivs.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as phenol, 2-[[[3-(dimethylamino)propyl]amino]methyl]-6-methyl-, 4-polybutene derivs. (PMN P–99–0531; CAS No. 1078715–83–9) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 17. In § 721.4620, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.4620 Zinc, bis(N,N-dipropyl-.beta.-alaninato-.kappa.N,.kappa.O)-, (T–4)-.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as zinc, bis(N,N-dipropyl-.beta.-alaninato-.kappa.N,.kappa.O)-, (T–4)- (PMN P–90–274; CAS No. 135364–47–5) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 18. In § 721.5262, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.5262 2,7-Naphthalenedisulfonic acid, 5-[[4-chloro-6-[[2-[2-(ethenylsulfonyl)ethoxy]ethyl]amino]-1,3,5-triazin-2-yl]amino]-4-hydroxy-3-[2-(1-sulfo-2-naphthalenyl)diazenyl]-, sodium salt (1:3).

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as 2,7-naphthalenedisulfonic acid, 5-[[4-chloro-6-[[2-[2-(ethenylsulfonyl)ethoxy]ethyl]amino]-1,3,5-triazin-2-yl]amino]-4-hydroxy-3-[2-(1-sulfo-2-naphthalenyl)diazenyl]-, sodium salt (1:3) (PMN P–00–0803; CAS No. 259795–03–4) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 19. In § 721.5325, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.5325 Nickel, tris(neodecanoato-.kappa.O)[.mu.3-[orthoborato(3-)-.kappa.O:.kappa.O′:.kappa.O″]]tri-.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as nickel, tris(neodecanoato-.kappa.O)[.mu.3-[orthoborato(3-)-.kappa.O:.kappa.O′:.kappa.O″]]tri- (PMN P–85–1034; CAS No. 936576–64–6) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 20. In § 721.5350, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.5350 Butanenitrile, 2-amino-2,3-dimethyl-.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as butanenitrile, 2-amino-2,3-dimethyl- (PMN P–83–603; CAS No. 13893–53–3) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 21. In § 721.8700, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.8700 Pyridine, 2,3-dichloro-5-(trifluoromethyl)-.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as pyridine, 2,3-dichloro-5-(trifluoromethyl)- (PMN P–83–237; CAS No. 69045–84–7) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 22. In § 721.9285, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.9285 Schiff bases, from ammonia-diethylene glycol reaction product fractionation forecuts and formaldehyde.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as schiff bases, from ammonia-diethylene glycol reaction product fractionation forecuts and formaldehyde (PMN P–95–535; CAS No. 172343–36–1) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 23. In § 721.9480, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.9480 Formaldehyde, polymer with 1,3-benzenediol and ethenylbenzene.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as formaldehyde, polymer with 1,3-benzenediol and ethenylbenzene (PMN P–89–769; CAS No. 135020–80–3) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 24. In § 721.9492, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.9492 Certain polymers of styrene, cyclohexyl methacrylate and substituted methacrylate.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substances identified as 2-propenoic acid, 2-methyl-, cyclohexyl ester, polymer with ethenylbenzene and 2-oxiranylmethyl 2-methyl-2-propenoate, tert-Bu 2-ethylhexaneperoxoate-initiated (PMN P–97–143; CAS No. 1078715–90–8) and as 2-propenoic acid, 2-methyl-, cyclohexyl ester, polymer with ethenylbenzene, 4-hydroxybutyl 2-propenoate and 2-oxiranylmethyl 2-methyl-2-propenoate, tert-Bu 2-ethylhexaneperoxoate-initiated (PMN P–97–144; CAS No. 1078715–62–4) are subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 25. In § 721.9497, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.9497 Certain trifunctional ketoximino silanes.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substances identified generically as trifunctional ketoximino silane (PMN P–95–0605) and as 2-pentanone, 4-methyl-, O,O′,O″-(methylsilylidyne)trioxime (PMN P–95–0606; CAS No. 37859–57–7) are subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 26. In § 721.9635, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.9635 Terpenes and terpenoids, limonene fraction, distn. residues, distillates.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as terpenes and terpenoids, limonene fraction, distn. residues, distillates (PMN P–96–0897; CAS No. 166432–37–7) is subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 27. In § 721.9720, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.9720 Certain disubstituted alkyl triazines.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substances identified generically as disubstituted alkyl triazines (PMN P–85–0932) and as 1,3,5-triazin-2-amine, 4-methoxy-N,6-dimethyl- (PMN P–85–0933; CAS No. 5248–39–5) are subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 28. In § 721.9730, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.9730 Certain 1,3,5-triazine-2-amine, 4-dimethylamino-6-substituted.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substances identified generically as 1,3,5-triazine-2-amine, 4-dimethylamino-6-substituted (PMN P–92–0343) and as 1,3,5-triazine-2,4-diamine, N2,N2-dimethyl-6-(2,2,2-trifluoroethoxy)- (PMN P–92–0344; CAS No. 145963–84–4) are subject to reporting under this section for the significant new uses described in paragraph (a)(2) of this section.

* * * * *

■ 29. In § 721.9800, revise the section heading and paragraph (a)(1) to read as follows:

§ 721.9800 1,3,5-Triazine, 2,4,6-trichloro-, polymer with piperazine, reaction products with morpholine.

(a) *Chemical substance and significant new uses subject to reporting.* (1) The chemical substance identified as 1,3,5-triazine, 2,4,6-trichloro-, polymer with piperazine, reaction products with morpholine (PMN P–88–0436; CAS No. 1078142–02–5) is subject to reporting under this section for the significant

new uses described in paragraph (a)(2) of this section.

* * * * *

[FR Doc. 2014–14259 Filed 6–17–14; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 54

[WC Docket No. 10–90; DA 13–1113, FCC 13–73, FCC 13–97]

Connect America Fund

AGENCY: Federal Communications Commission.

ACTION: Final rule; announcement of effective date.

SUMMARY: In this document, the Federal Communications Commission (Commission) announces that the Office of Management and Budget (OMB) has approved, for a period of three years, an information collection associated with the Commission's *Universal Service—Connect America Fund,* Report and Orders and Order on Reconsideration (*Orders*). The Commission submitted revised information collection requirements for review and approval by OMB, as required by the Paperwork Reduction Act (PRA) of 1995 (44 U.S.C. 3501–3520), which were approved by the OMB. This notice is consistent with the *Orders,* which stated that the Commission would publish a document in the **Federal Register** announcing the effective date of new information collection requirements.

DATES: The rules associated with the Connect America Phase II state-level commitment elections published at 78 FR 32991, June 3, 2013; 47 CFR 54.312(b)(3), published at 78 FR 48622, August 9, 2013; and 47 CFR 54.313(b) published at 78 FR 38227, June 26, 2013, are effective June 18, 2014.

FOR FURTHER INFORMATION CONTACT: Ryan Yates, Wireline Competition Bureau at (202) 418–7400 or TTY (202) 418–0484.

SUPPLEMENTARY INFORMATION: This document announces that, on March 11, 2014, OMB approved, for a period of three years, the information collection requirements contained in the Commission's *Orders,* DA 13–1113, published at 78 FR 32991, June 3, 2013, FCC 13–73, published at 78 FR 38227, June 26, 2013, and FCC 13–97, published at 78 FR 48622, August 9, 2013. The OMB Control Number is 3060–1188. The Commission publishes this notice as an announcement of the effective date of the new rules associated with the Connect America Phase II state-level commitment elections, 47 CFR 54.312(b)(3), and 54.313(b). If you have any comments on the burden estimates listed below, or how the Commission can improve the collections and reduce any burdens caused thereby, please contact Leslie Smith, Federal Communications Commission, Room 1–C216, 445 12th Street SW., Washington, DC 20554. Please include the OMB Control Number, 3060–1188, in your correspondence. The Commission will also accept your comments via email. Please send them to *PRA@fcc.gov*.

To request materials in accessible formats for people with disabilities (Braille, large print, electronic files, audio format), send an email to *fcc504@fcc.gov* or call the Consumer and Governmental Affairs Bureau at (202) 418–0530 (voice), (202) 418–0432 (TTY).

Synopsis

As required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3507), the FCC is notifying the public that it received OMB approval on March 11, 2014, for the new rules associated with the Connect America Phase II state-level commitment elections and the information collection requirements contained in the Commission's rules at 47 CFR 54.312(b)(3), and 54.313(b). Under 5 CFR part 1320, an agency may not conduct or sponsor a collection of information unless it displays a current, valid OMB Control Number.

No person shall be subject to any penalty for failing to comply with a collection of information subject to the Paperwork Reduction Act that does not display a current, valid OMB Control Number. The OMB Control Number is 3060–1188.

The foregoing notice is required by the Paperwork Reduction Act of 1995, Public Law 104–13, October 1, 1995, and 44 U.S.C. 3507.

The total annual reporting burdens and costs for the respondents are as follows:

OMB Control Number: 3060–1188.

OMB Approval Date: March 11, 2014.

OMB Expiration Date: March 31, 2017.

Title: Connect America Challenge Process and Certifications, WC Docket No. 10–90.

Form No.: FCC Form 505.

Respondents: Business or other for-profit, not-for-profit institutions, and state, local or tribal government.

Number of Respondents and Responses: 178 respondents; 178 responses.

Estimated Time per Response: 3 hours to 20 hours.

Frequency of Response: On occasion reporting requirement and third party disclosure requirements.

Obligation to Respond: Required to obtain or retain benefits. Statutory authority for this information collection is contained in 47 U.S.C. sections.

Total Annual Burden: 1,793 hours.

Total Annual Cost: N/A.

Nature and Extent of Confidentiality: The Commission is not requesting that respondents submit confidential information to the Commission. However, respondents may request materials or information submitted to the Commission or to the Universal Service Administrative Company (USAC) be withheld from public inspection under 47 CFR 0.459 of the Commission's rules. We note that USAC must preserve the confidentiality of all data obtained from respondents; must not use the data except for purposes of administering the universal service programs; and must not disclose data in company-specific form unless directed to do so by the Commission.

Needs and Uses: In documents DA 13–1113 and FCC 13–73, the Commission proposed to collect information to determine what areas should be eligible for Phase II of Connect America Fund and to ensure that Connect America Fund Phase I deployment occur in areas that are eligible for support. In document FCC 13–97, the Commission made mandatory the reporting of changes in deployment location involving census blocks that were not previously been identified. The information collection requirements announced in this notice further the Commission's goals under section 254(b) of the Communications Act to ensure that consumers in all regions of the Nation have access to telecommunications and information services, while minimizing waste, fraud, and abuse. Certain of the requirements covered by this information collection had been previously approved by OMB for a period of six month, 78 FR 44893, July 25, 2013. OMB has approved a renewal of these information collections for three years, in addition to approving the new information collections discussed herein. This information will be used to determine the amount of, and eligibility for, high-cost universal service support received by incumbent and competitive eligible telecommunications carriers under the Connect America Fund. To aid in collecting this information regarding the Phase II challenge process in a uniform fashion, FCC Form 505 will be used, which parties should use in filing their

Phase II challenges and responses with the FCC.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

[FR Doc. 2014–14292 Filed 6–17–14; 8:45 am]

BILLING CODE 6712–01–P

Proposed Rules

Federal Register

Vol. 79, No. 117

Wednesday, June 18, 2014

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.

NUCLEAR REGULATORY COMMISSION

10 CFR Parts 26 and 73

[NRC–2014–0118]

RIN 3150–AJ41

Enhanced Security at Fuel Cycle Facilities; Special Nuclear Material Transportation

AGENCY: Nuclear Regulatory Commission.

ACTION: Draft regulatory basis; request for comment.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) is requesting comments on a draft regulatory basis to support the potential amendments to revise a number of existing security-related regulations relating to physical protection of special nuclear material (SNM) at NRC-licensed facilities and in transit, as well as the fitness for duty programs for security officers at certain fuel cycle facilities. Potentially affected licensees include fuel cycle facilities, non-power reactors, research and development facilities, industrial facilities, and certain medical isotope production facilities.

DATES: Submit comments by August 4, 2014. Comments received after this date will be considered if it is practical to do so, but the NRC is only able to ensure consideration of comments received on or before this date.

ADDRESSES: You may submit comments by any of the following methods (unless this document describes a different method for submitting comments on a specific subject):

- *Federal rulemaking Web site:* Go to *http://www.regulations.gov* and search for Docket ID NRC–2014–0118. Address questions about NRC dockets to Carol Gallagher; telephone: 301–287–3422; email: *Carol.Gallagher@nrc.gov.* For technical questions, contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section of this document.
- *Email comments to: Rulemaking.Comments@nrc.gov.* If you do not receive an automatic email reply confirming receipt, then contact us at 301–415–1677.
- *Fax comments to:* Secretary, U.S. Nuclear Regulatory Commission at 301–415–1101.
- *Mail comments to:* Secretary, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, ATTN: Rulemakings and Adjudications Staff.
- *Hand deliver comments to:* 11555 Rockville Pike, Rockville, Maryland 20852, between 7:30 a.m. and 4:15 p.m. (Eastern Time) Federal workdays; telephone: 301–415–1677. For additional direction on obtaining information and submitting comments, see ''Obtaining Information and Submitting Comments'' in the **SUPPLEMENTARY INFORMATION** section of this document.
- *Comments that contain proprietary or sensitive information:* Please contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section of this document to determine the most appropriate method for submitting these comments.

FOR FURTHER INFORMATION CONTACT: Alex Sapountzis, Office of Nuclear Security and Incident Response, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; telephone: 301–287–3660, email: *Alexander.Sapountzis@nrc.gov*.

SUPPLEMENTARY INFORMATION:

I. Obtaining Information and Submitting Comments

A. Obtaining Information

Please refer to Docket ID NRC–2014–0118 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 Web site:* Go to *http://www.regulations.gov* and search for Docket ID NRC–2014–0118.
- *NRC's Agencywide Documents Access and Management System (ADAMS):* You may obtain publicly-available documents online in the ADAMS Public Documents collection at *http://www.nrc.gov/reading-rm/adams.html.* To begin the search, select ''*ADAMS Public Documents''* and then select ''*Begin Web-based ADAMS Search.''* For problems with ADAMS, please contact the NRC's Public Document Room (PDR) reference staff at 1–800–397–4209, 301–415–4737, or by email to *pdr.resource@nrc.gov.* The draft regulatory basis document is available in ADAMS under Accession No. ML14113A468.
- *NRC's PDR:* You may examine and purchase copies of public documents at the NRC's PDR, Room O1–F21, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852.

B. Submitting Comments

Please include Docket ID NRC–2014–0118 in the subject line of your comment submission, in order to ensure that the NRC is able to make your comment submission available to the public in this docket.

The NRC cautions you not to include identifying or contact information in comment submissions that you do not want to be publicly disclosed in your comment submission. The NRC will post all comment submissions at *http://www.regulations.gov* as well as enter the comment submissions into ADAMS, and 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. Discussion

The NRC is requesting comment on a draft regulatory basis to support rulemaking to amend portions of Parts 26 and 73 of Title 10 of the *Code of Federal Regulations* (10 CFR) to strengthen physical protection of SNM at NRC-licensed facilities and in transit, as well as strengthen fatigue programs for security officers at certain fuel cycle facilities. The draft regulatory basis supports potential rulemaking efforts related to: (1) Enhanced security at fuel cycle facilities; (2) special nuclear material transportation security; and (3) security-force fatigue at certain nuclear facilities.

The specific objectives of these rulemaking efforts are to update SNM physical protection requirements to: (1) Improve consistency and clarity; (2) make generically applicable security requirements similar to those imposed by security orders issued after the terrorist attacks of September 11, 2001; (3) consider risk insights from new National Laboratory studies, operational oversight and inspection activities, and international guidance; and (4) use a risk-informed and performance-based structure. The scope of the regulatory basis includes physical protection of SNM at fuel cycle facilities and other facilities that possess and use SNM, and the physical protection of SNM in transit. Potentially affected licensees include fuel cycle facilities, non-power reactors, research and development facilities, industrial facilities, and certain medical isotope production facilities. The regulatory basis, in part, explains why the NRC believes the existing regulations should be updated, revised and enhanced, presents alternatives to rulemaking, and discusses cost and other impacts of the potential changes.

III. Specific Requests for Comments

The NRC requests that stakeholders consider answering the following questions when commenting on the draft regulatory basis:

- Is the NRC considering an appropriate approach for each objective described in the draft regulatory basis? Should implementing material attractiveness and its associated physical protection measures be ''voluntary'' or should it be ''mandatory?'' Given that the potentially revised regulations would be material-based rather than facility-based, are the potential regulatory changes sufficiently performance-based to allow licensees of different facility types to effectively implement the potential physical protection performance objectives and strategies for the various categories of special nuclear material?
- Section 3 of the draft regulatory basis discusses the regulatory problems the NRC expects to address through rulemaking. Section 4 presents the desired regulatory changes to address those regulatory problems and Section 5 discusses alternatives to rulemaking considered by the NRC staff. Are there other regulatory problems within or related to the scope of the rulemaking efforts (see Section 1) that the NRC should consider? Are there other approaches or alternatives the NRC should consider to resolve those regulatory problems?
- Section 8 of the draft regulatory basis presents the NRC staff's initial assessment of cost and other impacts for a number of key aspects of the potential regulatory changes (i.e., fixed site physical protection, transportation physical protection, safety-safeguards interface and fitness-for-duty impacts). The NRC staff recognizes that this initial assessment is based on limited data. As such, staff is seeking additional data and input relative to expected and/or unintentional impacts from the desired regulatory changes. What would be the potential impacts to stakeholders/licensees from implementing any of the desired regulatory changes described in this draft regulatory basis (e.g., what would be a reasonable cost estimate for implementation of fatigue requirements for security officers at Category I facilities in accordance to 10 CFR Part 26, Subpart I, including startup and annual costs)?
- The NRC staff recognizes that the security officer work hour data provided voluntarily by licensees in the past and summarized in Attachment 2 of the draft regulatory basis is limited. As such, are there additional data or information (e.g., procedures that demonstrate the licensee has fatigue measures in place for security officers at their site, updated security officer work hour data from the most recent 2-month period and so forth) that would inform the NRC staff's assessment or analysis?

IV. Publicly Available Documents

The NRC may post additional materials related to this rulemaking activity to the Federal rulemaking Web site at *www.regulations.gov*, under Docket ID NRC–2014–0118. By making these documents publicly available, the NRC seeks to inform stakeholders of the current status of the NRC's rulemaking development activities and to provide preparatory material for future public meetings.

The Federal rulemaking Web site allows you to receive alerts when changes or additions occur in a docket folder. To subscribe: (1) Navigate to the docket folder (NRC–2014–0118); (2) click the ''Sign up for Email Alerts'' link; and (3) enter your email address and select how frequently you would like to receive emails (daily, weekly, or monthly).

V. Plain Writing

The Plain Writing Act of 2010 (Pub. L. 111–274) requires Federal agencies to write documents in a clear, concise, well-organized manner. The NRC has written this document to be consistent with the Plain Writing Act as well as the Presidential Memorandum, ''Plain Language in Government Writing,'' published June 10, 1998 (63 FR 31883). The NRC requests comment on this document with respect to the clarity and effectiveness of the language used.

Dated at Rockville, Maryland, this 10th day of June, 2014.

For the Nuclear Regulatory Commission.

Christopher G. Miller,

Director, Division of Intergovernmental Liaison and Rulemaking, Office of Federal and State Materials and Environmental Management Programs.

[FR Doc. 2014–14135 Filed 6–17–14; 8:45 am]

BILLING CODE 7590–01–P

FEDERAL TRADE COMMISSION

16 CFR Part 305

RIN 3084–AB03

Energy Labeling Rule

AGENCY: Federal Trade Commission (''FTC'' or ''Commission'').

ACTION: Supplemental notice of proposed rulemaking.

SUMMARY: As part of its regulatory review of the Energy Labeling Rule, the Federal Trade Commission proposes to expand coverage of the Lighting Facts label, change the current label categories for refrigerators, revise the ceiling fan label design, and require room air conditioner labels on packaging instead of the units themselves.

DATES: Written comments must be received on or before August 18, 2014.

ADDRESSES: Interested parties may file a comment online or on paper, by following the instructions in the Request for Comment part of the **SUPPLEMENTARY INFORMATION** section below. Write ''Supplementary Notice of Proposed Rulemaking on Energy Labeling Rule Regulatory Review (16 CFR Part 305) (Project No. R611004)'' on your comment, and file your comment online at *https://public.commentworks.com/ftc/energyguidereview* 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 B), Washington, DC 20580, or deliver your comment to the following address: Federal Trade Commission, Office of the Secretary, Constitution Center, 400 7th Street SW., 5th Floor, Suite 5610 (Annex B), Washington, DC 20024.

FOR FURTHER INFORMATION CONTACT: Hampton Newsome, Attorney, (202)

326–2889, Division of Enforcement, Bureau of Consumer Protection, Federal Trade Commission, 600 Pennsylvania Avenue NW., Washington, DC 20580.

SUPPLEMENTARY INFORMATION:

I. Background

In a March 15, 2012 **Federal Register** Notice (77 FR 15298) (''Notice of Proposed Rulemaking'' or ''NPRM''), the Federal Trade Commission (''FTC'' or ''Commission'') initiated a review of the Energy Labeling Rule seeking comment on several proposed improvements to the FTC's labeling requirements.[1] On January 10, 2013, the Commission issued final amendments to streamline data reporting and to improve online disclosures as proposed in the March 2012 NPRM.[2] This NPRM also proposed new labels to help consumers comparison shop for refrigerators and clothes washers after the implementation of upcoming changes to the Department of Energy (DOE) test procedures. The Commission issued final amendments for those issues, as well as updates to comparability ranges, on July 23, 2013 (78 FR 43974).[3]

II. Remaining Regulatory Review Issues

This document addresses the remaining issues raised by the Commission or commenters during this regulatory review proceeding and proposes related amendments. These issues include expanded light bulb label coverage, an online label database, more durable labels for appliances, room and portable air conditioner box labels, ceiling fan labels, consolidated refrigerator ranges, updates to furnace labels, QR (''Quick Response'') Codes, bilingual issues, television label updates, a range revision schedule, retailer responsibility, marketplace Web sites, set-top box labeling, clothes dryer labels, and plumbing products. After reviewing the comments received in response to this document, the Commission will publish final amendments as appropriate.

A. Expanded Light Bulb Labeling

The Commission proposes requiring the Lighting Facts label for decorative and other specialty bulbs that have energy use and light output similar to general service bulbs already labeled under the Rule. On July 19, 2010 (75 FR 41696), the Commission created a new Lighting Facts label for general service light bulbs, which discloses information about the bulb's brightness, estimated annual energy cost, life, color appearance, and energy use.[4] The current labeling rules cover most general service medium screw base incandescent, compact fluorescent, and LED (light-emitting diode) bulbs.[5] They exclude several other common consumer bulbs, such as decorative bulbs (*e.g.,* globe and bent-tip decorative bulbs rated 40 watts or fewer), non-medium screw base bulbs, shatter-resistant bulbs, and vibration service bulbs.[6] In 2011, the Commission proposed labeling for specific bulb shapes generally available to consumers and not covered by the labeling requirements.[7] Specifically, the Commission proposed to expand label coverage to include all screw-based bulbs and GU–10 and GU–24 pin-based bulbs to provide consumers uniform information, such as energy cost, brightness, and bulb life, to help them with their lighting decisions.

Comments: The comments offered conflicting views on the proposal.[8] In support of the proposal, the Natural Resources Defense Council (NRDC) (#00006–80665) urged expanded coverage for all screw-base lamps, certain pin-based lamps, and any lamp (*i.e.,* bulb) used as a substitute for general service lamps.[9] Specifically, it recommended new labeling for all screw-based lamps regardless of shape, base size, or technology to ensure lamp purchasers receive basic information about light output, operating cost, lifetime, power, use, and color temperature. It also noted that many of the unlabeled bulbs use significant amounts of energy and are available in different technologies. For example, some candelabra-based lamps consume up to 60 watts and frequently appear in fixtures containing five or more sockets. In addition, manufacturers offer alternatives to incandescent candelabra bulbs in efficient compact-flourescent (CFL) or LED versions, which suggests labeling may aid consumers in comparing these bulb types across different technologies.[10] NRDC also supported the proposal to require labels for GU–10 and GU–24 pin-based lamps given their increasing use in new construction, remodels, and commercial spaces. It noted that current packaging for some of these products does not disclose light output.

ASAP, which also supported expanded coverage, focused on labeling bulbs commonly used as substitutes for general service lamps.[11] For example, ASAP supported labeling for rough-service and shatter-resistant lamps because their shape, base, and wattage resemble general service incandescent products. ASAP noted that rough-service light bulbs (60, 75, and 100 watt versions) often sell for about one dollar and shatter-resistant bulbs sell for less than two dollars, which increases the likelihood that consumers will purchase such bulbs for use as general lighting. Similarly, NRDC urged labels for appliance lamps, three-way lamps, and plant lights because these lamps serve as ''one-for-one replacements'' for inefficient incandescent light bulbs, but do not fall under existing federal efficiency standards.[12]

In contrast, industry comments argued that Commission's proposal was too broad and would require labels that, in some cases, would provide little benefit to consumers. Instead, they urged the Commission to consider expanded coverage on a product-by-product basis and only impose new requirements if labeling for specific bulb types would aid consumer-purchasing decisions. They also urged the Commission to allow a smaller version of the label for small packages common for specialty bulbs. Finally, these comments opposed the proposal to

[1] The comments received in response to the March 2012 regulatory review notice can be found at *http://ftc.gov/os/comments/energylabelamend/index.shtm.*

[2] On January 9, 2013 (78 FR 1779), the Commission published a proposed rule seeking comment on updated ranges of comparability and unit energy cost figures for many EnergyGuide labels.

[3] Additional related proceedings are discussed in this document.

[4] 16 CFR 305.15(b). The Energy Independence and Security Act of 2007 (EISA) directed the Commission to examine existing light bulb labeling requirements. Public Law 110–140; *see* 42 U.S.C. 6294(a)(2)(D)(iii). EISA amended the Energy Policy and Conservation Act (EPCA) (42 U.S.C. 6291 *et seq.*).

[5] 16 CFR 305.3(l).

[6] 16 CFR 305.3(l)(2), (n)(3)(ii).

[7] 76 FR 45715 (Aug. 1, 2011). The Notice also sought comments on bilingual labeling (but did not propose any bilingual requirements).

[8] The comments can be found at *http://www.ftc.gov/os/comments/lampcoveragenprm/index.shtm.* Unless otherwise stated, comments discussed in this section refer to the following: Appliance Standards Awareness Project (ASAP) (#00008–80686); GE Lighting (#00005–80686); Lee (#00007–80686); Moore (#00004–80686); National Electrical Manufacturers Association (NEMA) (#00009–80686); and Natural Resources Defense Council (#00006–80686).

[9] This document uses the terms lamp, light bulb, and bulb interchangeably.

[10] NRDC also recommended that DOE amend the definition of general service lamp to clarify that halogen lamps are covered. Because the Rule's definition of incandescent lamp (16 CFR 305.3(n)) already includes the term ''halogen,'' the Commission is not proposing an amendment.

[11] Specifically, ASAP explained that converter bases can allow substitution of candelabra and intermediate-base lamps for general service lamps. The Commission notes that EPCA already prohibits sale of adapters designed to ''allow an incandescent lamp that does not have a medium screw base to be installed into a fixture or lampholder with a medium screw base socket.'' 42 U.S.C. 6302(6).

[12] The current labeling requirements already cover three-way lamps. *See* 16 CFR 305.3(l)(1), (n)(3); and 75 FR 41698, n. 13.

change the definition of ''general service lamp'' as a vehicle to expand label coverage.

The National Electrical Manufacturers Association (NEMA) (#00009–80665), a lighting industry association, raised concerns about the proposal's breadth. NEMA argued that expanded coverage would yield little benefit because consumers have minimal concern about lumen output and energy use when purchasing many of the bulb types included in the Commission's proposal.[13] In NEMA's view, the broad proposal conflicts with the statute's primary focus on ''general service lamps,'' the most common lamp types that satisfy a majority of lighting applications.[14] For example, according to NEMA, intermediate screw base incandescent lamps, unlike ''general service lamps,'' [15] have extremely low sales volume, have few CFL or LED alternatives, and appear in unusual locations such as desk lamps, appliances, and show cases.

NEMA added that candelabra based lamps are small, decorative bulbs with limited space for labeling and that few pin-based lamps (GU-type) are sold to residential consumers. It also explained that the proposal would cover products with low sales or minor energy use, such as B, BA, CA, and G shape lamps that draw fewer than 30 watts or produce fewer than 310 lumens; small diameter reflector lamps with few sales (*e.g.,* MR–14 lamps); low-wattage night lights (C–7 shape) decorative flame-shapes with little market presence; and low lumen LEDs.[16]

In addition, GE noted the proposal covered several commercial bulb shapes with few, if any, high-efficiency alternatives, such as S-lamps and T-lamps used for exit signs, showcases, and appliances. Finally, NEMA recommended that the FTC maintain the Rule's current exclusions,[17] which mostly involve products purchased for their decorative and aesthetic appeal because consumers do not generally consider energy savings when purchasing these products.[18]

Although NEMA raised concerns with the proposal's structure and coverage, it acknowledged FTC's authority to consider labeling for additional lighting products. Industry comments, from NEMA and GE, urged the Commission to use that authority to focus on whether additional ''labeling or other disclosures will help consumers in making purchasing decisions'' as contemplated by EPCA.[19] GE added that the EPCA calls for disclosures ''necessary to enable consumers to select the most energy efficient lamps which meet their requirements.'' [20] Given this general guidance, GE suggested the Commission allow voluntary labeling for bulb types that: (1) Have high sales volumes; (2) compete with alternative technologies (*e.g.,* CFLs and LED bulbs); and (3) consume meaningful amounts of energy. NEMA noted that the statutory definitions for lighting products already identify the bulb types likely to yield significant energy savings if labeled. In its view, lamp products with low lumen levels, with low wattage levels, or otherwise designed for specialty applications do not qualify.

Both NEMA and GE recommended that the Commission approach any expanded coverage on a bulb-by-bulb basis to provide regulatory clarity and to ensure that substantial evidence exists for such requirements. GE pointed the Commission to a specific set of bulbs as good candidates for labeling. It explained that about 95% of the decorative incandescent lamp shapes are offered in the G (Globe), CA, B, or BA types, which are available in alternative technologies such as CFL or LED and feature medium screw, candelabra or intermediate screw bases. GE also recommended that the Commission focus on labeling for common lamp types rated at 25 or more watts because models below 25 watts do not consume enough energy to affect consumer purchasing behavior.

Industry members also raised concerns about fitting the required disclosures on packages and lamps. These comments recommended a smaller label and abbreviated content for newly-covered bulbs because many specialty lamp types have smaller packages. Specifically, NEMA urged the Commission to allow a smaller version of the label, which discloses only brightness (average initial lumens), life, and energy usage (wattage). NEMA also repeated its earlier proposal to allow the Rule's current compressed label for packages up to 48 square inches in size, instead of the Rule's current 24 square inch threshold.[21] In addition, NEMA argued that the current requirement that the products be marked with mercury and lumen information [22] is not feasible for many of the small specialty lamps. It indicated that marking could interfere with some bulbs' aesthetic appeal, damaging their popularity.[23]

Finally, NEMA and GE strongly opposed the Commission's proposal to change the definition of ''general service lamp'' to expand label coverage. Because EPCA contains a specific definition for ''general service lamp,'' which is used mostly to define the scope of DOE's efficiency standards, NEMA warned that the proposed amendment would create inconsistencies between FTC and DOE regulations and sow confusion. NEMA also argued that the Commission does not have authority to amend the statutory definition of ''general service lamp'' because EPCA reserves such authority to the Secretary of Energy (42 U.S.C. 6291(30)(BB)(i)(IV)). NEMA acknowledged that the Commission has authority to require labeling for consumer products under 42 U.S.C. 6294(a)(6), but argued that, in exercising this power, the Commission should not use definitions inconsistent with EPCA.

Discussion: The Commission revises its proposal to cover specialty bulb types with energy use or light output similar to the general service bulbs already covered by the Lighting Facts label. This new proposal is consistent with EPCA's directive to develop labels that help consumers with their

[13] NEMA also noted that many such lamps operate on dimmers, allowing consumers to reduce their lumen and wattage level to provide ambient illumination, thus creating variations in the actual energy costs of these products.

[14] *See e.g.,* 42 U.S.C. 6292(a)(14).

[15] General service incandescent lamps instead have ''medium'' screw bases. *See* 16 CFR 305.3(n)(3).

[16] As part of its comments, NEMA included a chart listing several types of specialty bulbs detailing their typical use, purchasers, substitutes, and sales volume. NEMA detailed objections to the inclusion of the following bulb shapes: F(''flame'') lamps (constitute less than 1% of the incandescent market and have irregular surfaces which prevent direct printing on the bulb itself), M–14 lamps (''have essentially no meaningful sales today'' according to GE (#00005–80665)), C–7 lamps (incandescent night lights which use no more than 4 watts), and decorative CA lamps (use under 25 watts).

[17] The current requirements exclude G shape lamps (as defined in ANSI C78.20–2003 and C79.1–2002) with a diameter of 5 inches or more; T shape lamps (as defined in ANSI C78.20–2003 and C79.1–2002) that use not more than 40 watts or have a length of more than 10 inches; and B, BA, CA, F, G16–1/2, G–25, G30, S, or M–14 lamps (as defined in ANSI C79.1–2002 and ANSI C78.20–2003) of 40 watts or less. 16 CFR 305.3(l), (n)(3)(ii)(R)–(T).

[18] NEMA noted that EPCA provides a mechanism for DOE to impose efficiency standards for specialty lamps, such as rough or vibration service lamps, if the sales volumes of these products increase. 42 U.S.C. 6295.

[19] 42 U.S.C. 6294(a)(6).

[20] 42 U.S.C. 6294(a)(2)(D).

[21] *See* 16 CFR 305.15(b)(5). The current Rule's compressed label contains the same content as the standard label, but in a smaller format. NEMA explains that this compressed label is still too large, and thus requests a smaller label.

[22] *See* 16 CFR 305.15(b)(7).

[23] NEMA further proposed that the Rule allow manufacturers to self-certify and forgo reporting for these products given their low energy usage and the fact that neither Congress nor DOE has included them in the DOE energy conservation standards program.

purchasing decisions.[24] The proposal sets specific thresholds for wattage and light output for bulbs that must bear the label and excludes bulbs with shapes or uses not generally sought by typical consumers (*e.g.,* mine service bulbs). It includes special marking provisions for some bulb types and provides a smaller, single-label option for the smaller packages often used for specialty bulbs. For consumer light bulbs not covered by the proposed requirements, the proposal allows manufacturers to use the Lighting Facts label if they follow the Rule's content and format requirements. Finally, to avoid confusion, the Commission proposes implementing the expanded coverage by adding the term ''specialty consumer lamp'' to the Rule instead of amending the Rule's definition of ''general service lamp.''

Under EPCA, the Commission can require labeling for any consumer product if such labeling is ''likely to assist consumers in making purchasing decisions.'' [25] Therefore, the Commission may look beyond EPCA's specific lamp definitions, which generally circumscribe the coverage for DOE's efficiency standards.[26] This expansive authority is further demonstrated by EPCA's direction that the FTC issue labeling requirements that ''enable consumers to select the most energy efficient lamps which meet their needs.'' [27] In addition, without specifying bulb coverage, the 2007 EPCA amendments encouraged the Commission to revise labels to help consumers ''understand new high-efficiency lamp products'' and allow them to choose products that meet their needs for light output, light quality, and lamp lifetime.[28]

Consistent with this statutory direction, the modified proposal covers lamp types with wattages and light output similar to currently covered general service bulbs. The new labels will provide a means for consumers to compare the energy use, brightness, and other attributes of different bulb types and technologies commonly available on the market. Specifically, the modified labeling proposal applies to bulbs that: (1) Are rated at 30 watts or higher or produce 310 lumens or more; (2) have a medium, intermediate, candelabra, GU–10, or GU–24 base; and (3) do not meet the definition of ''general service lamp.'' [29] The Commission proposes these specific criteria because the 30-watt and 310-lumen thresholds are consistent with Congressionally-established benchmarks set in EPCA's definition of ''general service lamps.'' [30] This proposal covers common product types likely to appear side-by-side on store shelves with general service bulbs.[31] Finally, it covers specialty bulbs that look and operate like traditional incandescent bulbs, but are currently excluded from coverage, such as vibration-service lamps, rough service lamps, appliance lamps, plant light lamps, and shatter-resistant lamps (including a shatter-proof lamp and a shatter-protected lamp).

The proposal excludes bulb types for which labeling may not provide substantial benefit to consumers, including bulbs that use less than 30 watts and produce low light output, or bulbs not typically purchased by residential consumers. It also specifically excludes uncommon bulb shapes, lamp types with little market presence, and bulbs generally used for commercial applications. The proposed exclusions are: black light lamps, bug lamps, colored lamps, infrared lamps, left-hand thread lamps, marine lamps, marine signal service lamps, mine service lamps, sign service lamps, silver bowl lamps, showcase lamps, traffic signal lamps, G-shape lamps with diameter of 5 inches or more, and C7, M–14, P, RP, S, and T-shape lamps.[32] The comments did not suggest that labeling for such products would help consumers with purchasing decisions. The Commission seeks comment on whether any of these bulb types should be included and, if so, why.

In addition to the labeling requirements, the proposal requires markings (*i.e.,* the lumen and mercury marking currently required for general service lamps) on certain bulb shapes.[33] For A-shape and spiral lamps, the Commission proposes requiring the same markings (*i.e.,* lumens and mercury) that currently apply to general service lamps because the size and shape of these bulbs is similar. The proposal does not require lumen markings on the lamps themselves for decorative size bulbs, including B, BA, BA, F, and G-shapes, to avoid detracting from those products' appearance. However, the proposal would require mercury disclosures on all covered bulbs containing mercury to ensure the consumers have access to such information for cleanup and disposal.[34]

The Commission proposes a smaller, single label option [Figure 1] that manufacturers may use on package fronts for certain specialty use bulbs to help fit the label on small packages.[35] Because packaging for some specialty bulbs may consist of a blister pack on a small, single-sided card, the current rules, which require disclosures on two separate panels, may not be feasible. The proposed smaller label discloses lumens, energy cost, and bulb life, but not watts and light appearance. Under the proposal, the smaller label would not apply to certain large bulbs, such as vibration-service lamps, that resemble general service lamps in size and function and thus are likely to have packaging similar to general service bulbs. Finally, consistent with the current marking requirements for general service bulbs, bulbs containing mercury would include the Rule's mercury disclosure in a clear and conspicuous manner on the product itself.

[24] 42 U.S.C. 6294(a)(2)(D), (a)(6).

[25] 42 U.S.C. 6294(a)(6).

[26] 42 U.S.C. 6291(30), 6292(a)(14). Recognizing that labeling may be appropriate for some products even in the absence of an efficiency standard, the Commission has already used this general authority to cover three-way incandescent bulbs and high-efficiency LED bulbs. *See* 75 FR 41698.

[27] *See* 42 U.S.C. 6294(a)(2)(D)(i).

[28] *See* 42 U.S.C. 6294(a)(2)(D)(iii) (the statute also directs the Commission to consider additional labeling changes to help consumers understand light bulb alternatives).

[29] On December 9, 2013 (78 FR 73737), DOE initiated a proceeding to consider whether to expand the current definition of ''general service lamp.'' The Commission will seek to ensure final labeling amendments harmonize with amended DOE definitions.

[30] *See* 42 U.S.C. 6291(30)(C)&(D).

[31] The following provides more specific information provided in NEMA's comments about the principal bulb types included in the proposal, including the bulb's common bases, their typical applications, and their general market volume:

A-Shape:—available in medium and intermediate bases; used in residential applications, including ceiling fans; used for incandescent rough service and shatter proof bulbs at high wattages;

B-shape:—decorative ''torpedo'' shaped bulbs used in residential applications; available in CFL and LED versions; NEMA comments suggest that 40-watt or fewer B-shape lamps account for about 7% of the incandescent market;

BA and CA shape:—bent tip decorative lamps used in residential settings; available with medium and candelabra bases; wattages as a high as 60; available in incandescent and LED versions; represents between 6–7% of the incandescent market according to NEMA comments;

F-Shape:—decorative flame-shaped bulb; use as much as 40 watts; available in CFL and LED versions;

G-Shape:—often used in residential bathrooms; available in CFL and LED versions; according to comments, G16 ½ lamps represent 2.5% of the incandescent market, G25 lamps represent 5%, and G30 lamps represent about 0.5%; and

Spiral shape:—commonly used for CFLs with intermediate screw bases and GU–24 pin-based bulbs; increasingly used in new construction.

[32] *See* proposed section 305.3(z)(3).

[33] 305.15(c)(2)(iii) (proposed).

[34] Because mercury disclosures generally apply only to compact fluorescent technology, manufacturers should be able to place such information on the ballast, where other information is commonly printed.

[35] 305.15(c)(2) (proposed).

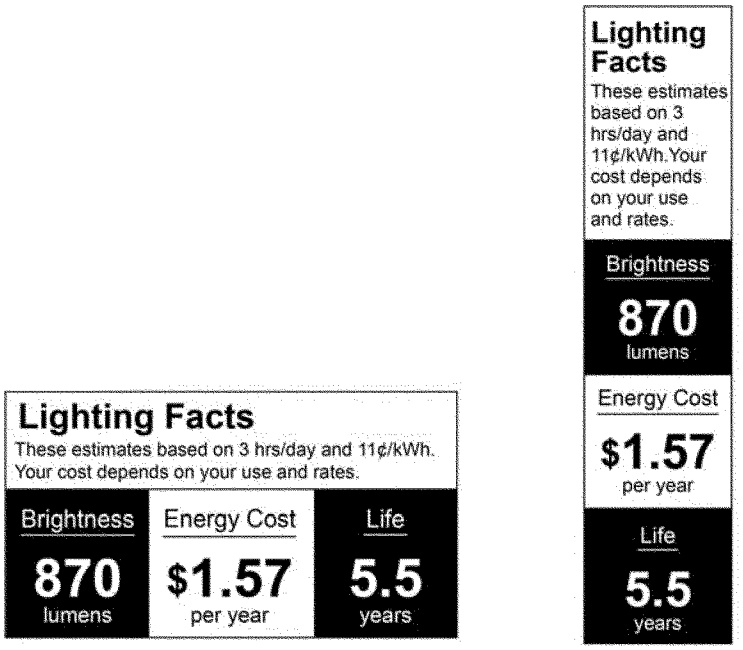


Figure 1 – Proposed Single-Panel Label Option for Specialty Bulbs

In seeking to expand coverage of the Lighting Facts label, the Commission does not propose altering the Rule's existing test procedure and reporting requirements. Under the current rule, manufacturers (or private labelers) must use DOE test procedures for lamp products covered by those DOE test procedures. If no existing DOE test procedure applies to a particular lamp, the Rule requires manufacturers to possess and rely upon a reasonable basis consisting of competent and reliable scientific tests and procedures substantiating the representation.[36] The Commission seeks comment on whether competent and reliable tests and procedures exist that manufacturers can use to derive the information for all the light bulbs covered by the expanded labeling proposal. Finally, because DOE has no comprehensive testing requirements for ''specialty'' bulbs covered by the new labeling proposal, the amendments contain no new reporting provisions.

For bulbs not covered by the proposal (*e.g.,* consumer bulbs rated below 30 watts and below 310 lumens), the amendments would allow, but not require, manufacturers to use the Lighting Facts label.[37] However, all Lighting Facts labels must follow the Rule's content and formatting requirements. Whether manufacturers use the Lighting Facts label or not, the FTC Act's general prohibition against deceptive claims requires manufacturers to substantiate any light bulb claims they make with competent and reliable scientific evidence.[38]

Finally, consistent with NEMA's suggestions, the proposal does not alter the definition of ''general service lamp.'' Instead, the Commission proposes to create a new category of covered bulbs called ''specialty consumer lamps'' and identify the covered bulbs by shape, base, wattage, and lumen range. This approach will reduce confusion that may arise from changing the definition of ''general service lamp,'' which is also used in DOE's efficiency standards program. Finally, the Commission proposes a change to the definition of ''fluorescent lamp ballast'' to conform with a new DOE definition for those products.[39]

The Commission seeks comment on all aspects of this proposal. In particular, comments should address whether labeling for ''specialty consumer lamps'' will help consumers make purchasing decisions and, if so, whether that benefit is outweighed by increased labeling costs. In addition, commenters should address whether the lower wattage limit should be 30 watts, or a different figure.[40] Also, the Commission seeks comment on whether the Rule should allow, but not require, the label on products that do not meet the proposed definition of ''specialty consumer lamp.''[41] Finally, the Commission seeks comments on an appropriate compliance period for the proposed coverage.[42]

B. Online Label Database

Background: To streamline and consolidate the manufacturer reporting process, in January 2013, the Commission amended the Rule to permit reporting through DOE's

[36] 16 CFR 305.5(b).

[37] *See* 305.15(d) (proposed).

[38] 15 U.S.C. 45(a). The FTC staff has observed that the Lighting Facts label already appears widely on products that fall beyond the Rule's current coverage for general service lamps.

[39] *See* 76 FR 70548 (Nov. 14, 2011).

[40] The 30-watt figure is consistent with EPCA's definition of incandescent lamp (42 U.S.C. 6291(30)(C)).

[41] The Commission also received comments recommending additional mercury disclosures on the Lighting Facts label for CFLs, such as specific mercury content in milligrams and explicit warnings (Moore (#0004–80686) and Lee (#0007–80686)). The current label, which became effective in 2012, alerts consumers to the presence of mercury in light bulbs and directs them to the Environmental Protection Agency (EPA) Web site for more information. 16 CFR 305.15(b)(3)(viii). The Commission developed the mercury disclosures in a recent rulemaking after seeking public comment and coordinating with EPA, which has technical expertise and regulatory responsibility over mercury issues. 75 FR 41696 (July 19, 2010). Given this recent proceeding, the Commission is not proposing additional disclosures at this time. If the EPA recommends additional or different disclosures in the future, the Commission will consider changes to the label.

[42] In its NPRM (76 FR 45721), the Commission proposed a two-and-a-half year compliance period to minimize the likelihood that manufacturers will have to discard package inventory.

Compliance and Certification Management System (CCMS).[43] At the same time, the Commission required manufacturers to make copies of their EnergyGuide labels available on a publicly accessible Web site.[44] In doing so, the Commission aimed to improve the availability of online labels for retailers that sell covered products online.[45]

Comments: In response to the 2012 regulatory review notice, several commenters urged additional measures to make labels more available online. These recommendations included an online label database and the use of electronic labels in lieu of paper.

Seven energy-efficiency, environmental, and consumer advocacy organizations (#560957–00028) (''Joint Commenters'') [46] urged the FTC to develop an online label database maintained by the FTC or in conjunction with DOE. The Joint Commenters argued that the FTC and DOE databases [47] are insufficient because they contain neither copies of labels nor all the information necessary to replicate label content.

The Association of Home Appliance Manufacturers (AHAM) (#560957–00013), Whirlpool (#560957–00010), and BSH Home Appliance Corporation (BSH) (#560957–00007) urged the Commission to replace paper labeling with a publicly accessible online database. In support of this recommendation, these manufacturers reported that approximately two-thirds of consumers who purchased appliances in the prior year conducted online research prior to the purchase, and that more than 70% planned to do so for future purchases. Thus, the manufacturers concluded that having only online labels would be effective and sufficient. Whirlpool (#560957–00010) added that the FTC should create a public online version of the existing CCMS database, and expand it to consolidate FTC and DOE requirements. Whirlpool argued that label images should continue to be displayed on manufacturer and retailer Web sites, and noted that it currently provides electronic access to label images for all current products, until the product is declared obsolete. Similarly, Alliance (#560957–00011) questioned the necessity of paper labels in today's electronic age. Alliance supported use of the QR codes, but on a sign posted at point-of-sale instead of on a physical label.[48] Alliance argued that such a presentation would provide consumers quick access via smart phone to the FTC database and/or manufacturers' Web sites.

Discussion: The Commission agrees that a centralized public database with easy access to labels would benefit consumers. To that end, FTC and DOE staff are considering regulatory changes to require manufacturers to submit URL links for covered product labels to the DOE CCMS database. Specifically, manufacturers may be required to post a link to the Web page displaying the label corresponding to each of their covered products.[49] The Commission seeks comment on such a proposal.

This proposal should benefit consumers and retailers. Consumers will have access to a single comprehensive database at the DOE Web site containing label images for covered products. Online retailers will have access to digital labels for advertising, without submitting separate requests to manufacturers. Similarly, retailers that want to replace missing labels at the points-of-sale will be able to print replacements from the CCMS database.

The proposal should not create undue burdens on manufacturers. The Rule already requires manufacturers of most covered products to submit annual reports. DOE likewise requires manufacturers to make detailed electronic submissions through CCMS.[50] Additionally, manufacturers must display their labels online. The inclusion of URL links in those reports should not add significant burden to those existing requirements. Under the present proposal, a manufacturer could simply add a link on CCMS from its Web page displaying the label. In other words, the only additional burden upon manufacturers would be to paste URL links to Web pages that already exist and to delete links when removing or replacing the corresponding Web pages. Manufacturers will likely benefit by having a centralized online location through which to track and organize their web labels, which should help reduce the Rule's burden.

Because the proposed CCMS database would link to manufacturers' label Web pages, the Commission does not propose eliminating requirements related to such Web pages. Doing so would likely impose greater technical maintenance and coordination burdens on both DOE and manufacturers.

Finally, as explained above, the Commission does not propose abandoning physical labels at this time. Notwithstanding the growing availability of Internet access, physical labels, especially those displayed at the point-of-sale in stores, likely help a substantial number of consumers. The Commission recognizes the Internet's potential as a comprehensive source for energy consumption information, but not all consumers have online access, and not all those who do conduct online research before making purchase decisions. Moreover, even consumers who research products online may benefit from viewing the physical labels in the store.[51] The Commission will continue to consider evolving buying patterns and potential changes to the Rule.

C. More Durable Labels for Clothes Washers, Dishwashers, and Refrigerators

Background: In its March 15, 2012 NPRM, the Commission discussed the need to improve the availability of EnergyGuide labels in retailer showrooms. Evidence gathered by the FTC and the Government Accountability Office (GAO) in 2007 and 2008, respectively, demonstrated that many covered products displayed in retailer showrooms were missing the required EnergyGuide labels. For example, the FTC found labels either detached or missing on approximately 38% of the 8,500 appliances it examined across 89 retail locations in nine metropolitan areas.[52]

The Rule currently permits manufacturers of refrigerators, dishwashers, and clothes washers to post the required EnergyGuide labels either using adhesive labels or hang

[43] *See* 78 FR 2202–03 (amending 16 CFR 305.8).

[44] *See* 78 FR 2205 (amending 16 CFR 305.6). This amendment became effective on July 15, 2013.

[45] The Commission noted commentary arguing that many retailers do not use manufacturer Web sites to obtain labels. *See* 78 FR 2005, n.51.

[46] These organizations include Earthjustice, Consumers Union, Appliance Standards Awareness Project, American Council for an Energy-Efficient Economy, Natural Resources Defense Council, Alliance to Save Energy, and Public Citizen. This document shall refer to these organizations collectively as the ''Joint Commenters'' and to their comments as the ''Joint Comments.''

[47] *See https://www.regulations.doe.gov/ccms.* The FTC database has been recently consolidated with the DOE site. 78 FR 2200.

[48] AHAM, BSH, and Whirlpool opposed requiring manufacturers to display QR codes on labels, arguing that doing so would be burdensome and unnecessary, especially if labels are available in a centralized database.

[49] As explained in an earlier Notice, this requirement would not apply to private labelers, but manufacturers would be allowed to arrange with third parties, including private labelers, to display the labels and to submit the required links to CCMS. *See* 78 FR 2205.

[50] 10 CFR 429.12.

[51] 42 U.S.C. 6294(c)(3) (the Commission may require the label to be displayed in a manner that the Commission determines is likely to assist consumers in purchasing decisions).

[52] 77 FR 1300.

tags.[53] As part of its examination of more than 8,500 appliances sold by retailers, FTC staff found that products labeled with hang tags appear more likely to have detached or missing labels than those labeled with adhesives.[54] Additionally, comments received during the recent television rulemaking indicated that hang tags often become twisted or dislodged in stores, which supports the FTC staff's findings. Concerned that hang tags may be less secure and more prone to detachment than adhesive labels, the Commission, in its March 15, 2012 NPRM, proposed prohibiting hang tags for clothes washers, dishwashers, and refrigerators, and instead requiring adhesive labels.[55] The Commission sought comments on its proposal.

Comments: The comments were mixed. The Joint Commenters (#560957–00028) supported the proposal. They presented findings from a yearlong in-store labeling investigation, during which they visited 48 appliance showrooms and observed more than 2,500 displayed appliances across six product categories and 347 television units. Their investigation confirmed that '''hang tag' style'' labels become detached much more frequently than adhesive labels.[56] At the same time, they observed that labels attached by plastic cable ties or by strings with reinforced punch holes were more likely to remain attached. Accordingly, the Joint Commenters recommended that the Commission specify that labels be attached with more durable materials, such as adhesive-backed paper or with multiple strips of tape.

Like the Joint Commenters, three Western energy utilities recommended prohibiting hang tags.[57] However, they urged the Commission to require that adhesive labels leave no or minimal adhesive residue when peeled from the product, and that any adhesive residue be easy to clean using common household products.

Three manufacturers opposed an adhesive label-only requirement.[58] They argued that adhesive labels applied directly to products might leave marks or residual matter, especially on stainless steel products, which comprise nearly a third of major home appliances. They noted that affixing an adhesive to the protective film that covers products would be counterproductive because retailers likely would remove the film from display models, and may not reattach the label before displaying the product. They also explained that temperature and humidity might cause adhesive labels on products in storage or transit to become too sticky or lose their adhesive qualities. They also raised concerns about the anticipated additional capital and labor costs associated with a transition to adhesive labels. Finally, they explained that since many manufacturers display both U.S. and Canadian labels on a single double-sided hang tag, a transition to adhesive labels would force manufacturers to print two separate labels.

Manufacturers proposed several alternatives. As discussed in Section B, they recommended that the Commission abandon physical labels altogether. Arguing that physical labels are no longer relevant because consumers research product information online, they proposed that the Commission create an online database through which consumers can research products' energy efficiency.[59] If the Commission retains a physical label requirement, manufacturers argued that labels should be required only on showroom models.

However, manufacturers did not recommend prohibiting adhesive labels. Instead, they recommended retaining both the adhesive and hang tag options. Additionally, Whirlpool recommended requiring two strings for hang tags to reduce missing labels. AHAM proposed amending the Rule to allow hang tags on product exteriors, in addition to interiors.[60] AHAM argued that such an amendment would afford manufacturers greater flexibility in choosing hang tag placement to maximize consumer readability, providing a potential equivalent to adhesive labels affixed to product exteriors. Finally, manufacturers argued that if the Commission prohibits hang tags in favor of adhesive labels, it should permit smaller adhesive labels for clothes washers and dishwashers.

Discussion: The commenters raise compelling arguments against requiring only adhesive labels for clothes washers, dishwashers, and refrigerators. The Commission wants to avoid imposing labeling requirements that could lead to the damage of stainless steel products, causing significant costs to manufacturers. However, the Rule will retain adhesive labels as an option, allowing manufacturers to choose between adhesives (including flap tags) and improved hang tags. The Commission may reconsider requiring adhesive labels in the future if the proposed hang tag improvements do not sufficiently reduce the incidence of missing labels.

The Commission proposes amending the Rule (Section 305.11(d)(2)) to require that hang tags be affixed to products using cable ties (*i.e.,* ''zip ties''), double strings with reinforced punch holes, or material with equivalent or greater strength, connected with reinforced punch holes. These methods should improve label resilience, which in turn should reduce the incidence of missing labels. Additionally, they should not pose an undue burden for manufacturers, as suggested by Whirlpool's receptiveness to the double-string approach. The Commission invites additional comments on this proposal, including suggestions of other effective label attachment methods.

The Commission does not propose amending the Rule to allow hang tags to be affixed to products' exteriors because it is concerned about the heightened risk of detachment with exterior hang tags. The Commission prohibited exterior hang tags in 2007 to ''minimize the chance that labels will become dislodged from products.''[61] At that time, AHAM supported the prohibition, explaining that hang tags affixed to products' exteriors ''can be damaged or accidentally removed during distribution and therefore may be absent when products reach retail.''[62] The

[53] 16 CFR 305.11(d)–(e). Because the Rule does not allow hang tags on the exterior of appliances, manufacturers must use adhesive labels for products with no accessible interior (*e.g.* water heaters).

[54] *See* 77 FR 15300 & n.24.

[55] 77 FR 15299–15300. EPCA permits the Commission to prescribe the manner in which EnergyGuide labels are displayed 42 U.S.C. 6294(c)(3), (c)(9).

[56] Specifically, the Joint Commenters found that label attachment by string, plastic bobby pin, or directly onto a prong in the front of dishwasher top racks exhibit higher rates of detachment. They also found that labels attached with single strips of adhesive tape or strings connected to single strips of tape hung from the inside of products were more likely to be loose or missing.

[57] Comments of the Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SCGC), and San Diego Gas and Electric (SDG&E) (#560957–00009).

[58] Whirlpool Corporation (#560957–00010) and BSH Home Appliance Corporation (#560957–00007), as well as AHAM (#560957–00013). On the other hand, Alliance Laundry Systems LCC (#560957–00011) supported the proposed transition to adhesive labels, arguing that adhesive labels should reduce the incidence of missing labels on display models.

[59] AHAM, Whirlpool, and BSH Home Appliance Corporation argued that consumers' ability to research products online has diminished the usefulness of in-store information, citing 2012 research findings that nearly two-thirds of consumers who made major appliance purchases researched the products in advance and more than 70% plan to do so for future purchases.

[60] 16 CFR 305.11(e)(2) currently allows hang tags to be affixed to the interior of a product.

[61] 72 FR 49948 (Aug. 29, 2007).

[62] AHAM (#527896–00006). Despite AHAM's suggestion, the Commission is reluctant to undo the Rule's prohibition on exterior hang tags and rely solely on the Rule's catch-all provision (''as long as

Commission plans to pursue its current proposal for improved hang tag attachment methods before reconsidering its recent decision to prohibit exterior hang tags.

Finally, the Commission does not propose amending the Rule to include additional provisions suggested by the comments. First, the Commission does not propose prescribing more specific types of adhesive labels. Absent evidence of widespread problems caused by deficient adhesion methods, the Commission is reluctant to prescribe additional specific label attachment requirements that would reduce flexibility and may impose costs. Still, manufacturers should remain mindful that labels ''should be applied with an adhesive with an adhesion capacity sufficient to prevent their dislodgment during normal handling throughout the chain of distribution to the retailer or consumer.'' [63] Second, the Commission does not propose permitting smaller sized adhesive labels for clothes washers and dishwashers. Given the proposed retention of hang tags as an option, a smaller adhesive label size does not appear necessary. Third, the Commission does not propose limiting labels to display models. As the Commission explained in its recent television rulemaking, retailers may not receive specific products designated for display.[64] In addition, the appearance of labels on non-display models provides consumers useful energy consumption information after the purchase to help them understand the estimated energy use of their product. Finally, the Commission does not propose abandoning physical labels altogether in favor of online resources, as discussed in Section B above.

D. Labels on Room and Portable Air Conditioner Boxes

Background: In the 2012 Regulatory Review NPRM, the Commission proposed to require manufacturers to print or affix EnergyGuide labels on room air conditioner boxes instead of adhering them to the units themselves.[65] FTC staff has observed that retailers often display these products in boxes stacked on shelves or on the showroom floor, preventing consumers from examining the label before purchase. The proposed box label would address this problem.[66] The Commission proposed to provide manufacturers with at least two years to implement this change to minimize the burdens associated with package changes. In seeking comments, the Commission asked whether retailers typically display room air conditioners in, or out of, the box, and whether the proposal would accomplish the Commission's goal of consistently providing energy disclosures to consumers.

Comments: The comments offered conflicting views. Industry members, including AHAM (# 560957–00013) and Whirlpool (# 560957–00010), opposed the proposal. They asserted that box labeling is unnecessary because retailers usually display at least one unit of each model outside of the box to allow consumers to view and compare the models offered for sale. Furthermore, consumers viewing an unboxed display unit would have to locate the matching box to read the model's EnergyGuide label. Industry members also argued that the proposal would create an inconsistency with Canadian requirements, which require the label on the unit itself. This would decrease harmonization between the two programs and add significant cost by requiring manufacturers to use two labels.

AHAM also took issue with the proposal's complexity. It noted that the Commission would have to allow for black and white labels because many boxes are not printed in color. It also indicated that the label may not be visible to consumers if the box is stacked in a way that obscures the label. These comments also noted that the label may not easily fit on boxes for smaller room air conditioners, some of which are about a foot high. AHAM argued that, were the Commission to require box labels, it should allow manufacturers to use an adhesive sticker rather than printing the label directly on the box. Finally, AHAM asked whether the label would have to appear in multiple languages if other information on the box appeared in languages other than English.

In contrast, the Joint Commenters (# 560957–00015) urged the Commission to require labels on both boxes and the products themselves. In support, they cited store visit results indicating that retailers display units as often inside the box as outside. The Joint Commenters also recommended that the Commission follow the same approach for compact refrigerators and water heaters, noting that many stores they visited displayed these products in boxes while others displayed them only out of the box.[67] However, the store results provided by the Joint Commenters suggested that more compact refrigerator models were displayed outside the box than in. Additionally, the comments did not provide comparative information on the number of water heater models displayed outside of the box.[68]

Finally, AHAM requested that the Commission revise the label to require a new efficiency rating disclosure, noting that DOE has changed the energy efficiency metric for room air conditioners from energy efficiency ratio (EER) to a combined energy efficiency ratio (CEER).[69] The CEER accounts for the product's energy use in ''standby'' and ''off'' modes in addition to the ''active'' mode, whereas the EER only reflects the product's energy use in ''active'' mode. The new DOE rules that become mandatory on June 1, 2014 provide instructions for converting CEER ratings to estimated annual energy cost. According to AHAM, the change stemming from the CEER ratings is small.

Discussion: After considering the comments, the Commission proposes requiring the labels on room air conditioner boxes. The Commission does not propose changing existing labeling requirements for compact refrigerators and freezers and water heaters because these products do not appear to be predominantly displayed in boxes. Though some comments stated that retailers usually display at least one air conditioner model unit outside of the box, the store visit information from the Joint Commenters suggests that is not always the case. To follow up on these comments, the FTC staff visited more than 40 retail stores from six major retail chains in eight cities across the country and found that, in those locations, room air conditioner models are usually displayed either in the box only (50% of models observed) or both

the label will not become dislodged''), since this provision has not to date eliminated missing and obscured hang tags.

[63] 16 CFR § 305.11(d)(1).

[64] *See* 76 FR 1038, 1042 (Jan. 6, 2011).

[65] 77 FR 15300.

[66] The Commission has followed this approach with ceiling fan labels, which must appear on the principal display panel of packages. *See* 16 CFR 305.13(a)(3).

[67] The current Rule requires that EnergyGuide labels for these products be affixed to the products themselves, not the box. 16 CFR 305.11(d).

[68] In addition, PG&E (# 560957–00009) recommended that the Commission require water heater energy factor (EF) and central air conditioner seasonal energy efficiency ratio (SEER) information on packaging to help consumers and aid in compliance with state building code standards. For central air conditioners, the Commission recently required EnergyGuide labels, which include SEER information, on product packaging as part of the regional standards rulemaking. 78 FR 8362 (Feb. 6, 2013). For water heaters, it is unclear whether the benefits of including EF information on packaging justify its inclusion on packages because it is unlikely most consumers are familiar with the term. In addition, state code enforcers can easily obtain such EF information from DOE's Compliance Certification Management System (CCMS) database. *See https://www.regulations.doe.gov/ccms.*

[69] *See* 10 CFR 430.23(f)(5).

in the box with a few display units located on or near those boxes (29% of models observed).[70]

Under the proposal, manufacturers would have the flexibility to choose a background color for the label to avoid requiring some manufacturers to redesign their boxes. Manufacturers could also use stickers in lieu of printing the label on the box itself. This would allow them to update their labels in response to test procedure or range changes without creating new packaging. With sufficient lead-time, manufacturers should be able to incorporate the label on packaging with little or no additional burden.[71] Under the proposal, the labels must appear on the package's primary display panel, that part of a label that is most likely to be displayed, presented, shown, or examined under normal and customary conditions of display for retail sale.[72]

Accordingly, commenters should address whether this approach raises complications for routine label revisions due to range changes, cost updates, or test procedure amendments. Also, the Commission seeks comment on the amount of time necessary to effect these changes and the efficacy and burdens of requiring the label on the box.

The Commission is not proposing to require labels on both the product and the box. The burden of requiring physical labels in multiple locations likely outweighs the benefits from such additional disclosures, particularly given new provisions increasing the labels' availability to consumers online.[73]

Finally, the Commission proposes two changes related to recent DOE regulatory actions. First, it proposes to change the room air conditioner label to replace EER ratings with CEER ratings consistent with upcoming DOE changes for these products. According to commenters, the differences between EER and CEER should be minor. Therefore, the Commission only proposes a simple name change in Section 305.7 and sample label 4, which change the label's capacity description for these products. Second, the Commission proposes requiring EnergyGuide labels for portable air conditioners, in light of a recent DOE proposal to designate portable air conditioners as covered products under EPCA.[74] Given the similarity of portable air conditioners to room air conditioners, the Commission expects the Rule would require the same or similar labeling for the two products. The Commission would not require labeling until DOE completes a test procedure. Commenters should address whether portable air conditioners should be treated differently from room air conditioners for labeling purposes, and, if so, why.

E. Improved Ceiling Fan Labels

Background: The current label, which appears on product boxes and bears the title ''Energy Information,'' provides information on airflow (cubic feet per minute), energy use in watts, and energy efficiency (cubic feet per minute per watt) at high speed. In the March 2012 NPRM, the Commission proposed to require estimated annual energy cost information as the primary disclosure on the ceiling fan label.[75] As the Commission has stated in the past, consumer research suggests energy cost ''provides a clear, understandable tool to allow consumers to compare the energy performance of different models.'' [76] As with the EnergyGuide label for appliances, the new ceiling fan label would emphasize that ''Your cost depends on rates and use.'' The proposed yellow label features the familiar ''EnergyGuide'' logo. The Commission proposed using six hours and eleven cents per kWh/hour to calculate the label's cost disclosure.[77] To minimize the burden associated with this change, the Commission proposed providing manufacturers two years to change their packaging.

Comments: In response, two comments generally supported the proposed changes, but offered specific suggestions. Fanimation (#560957–00024) recommended label statements about energy savings from ceiling fans. It also recommended label usage and rate assumptions of one hour per day and ten cents per kWh or, alternatively, the same assumptions used on the Lighting Facts label (*i.e.,* three hours per day and elevent cents per kWh). Progress Lighting (# 560957–00022) recommended a usage assumption of three hours per day and urged the Commission to format the label to resemble the Lighting Facts label. Both Fanimation and Progress Lighting recommended that the Commission merge its label with that of the California Energy Commission (CEC) to provide consumers the range of costs to operate the fan on low, medium, and high speeds.[78]

Discussion: The Commission proposes changing the ceiling fan label as described in the NPRM. The proposed label continues to include a daily use assumption of six hours. Commenters offered no basis for alternative assumptions. In addition, the Commission proposes using an energy rate of twelve cents per kWh consistent with recent DOE national data used for other EnergyGuide labels.[79]

The proposed label follows the EnergyGuide label format, consistent with other products displayed in showrooms, such as refrigerators and clothes washers.[80] The suggested Lighting Facts format would require a new title, such as ''Energy Facts,'' reducing the consistency of FTC's energy labels. In addition, although fans often contain lights, they serve different functions and the current label excludes the energy use of any light bulbs attached to the fan. The Commission,

[70] Only 21% were displayed solely out of boxes. These results are based on FTC staff's review of more than 160 models (not individual units) offered for sale at a variety of stores in eight different metropolitan areas. The results are not necessarily nationally representative.

[71] Consistent with existing requirements for light bulb packaging, the proposed rule would not require bilingual labels for room air conditioners.

[72] *See, e.g.,* 15 U.S.C. 1459(f) (Fair Package and Labeling Act).

[73] Such measures include new requirements to ensure the label's presence on retailer and manufacturer Web sites published last year (78 FR 2200 (Jan. 10, 2013)) and, as proposed in this document, the inclusion of EnergyGuide labels on DOE's Web site.

[74] 78 FR 40403 (July 5, 2013). Portable air conditioners are movable units, unlike room air conditioners, which are permanently installed on the wall or in a window. If the Commission decides to require labels for these products, it will amend the Rule's coverage (and associated language) in a manner consistent with any final DOE determination.

[75] 77 FR 15302.

[76] 72 FR 49948, 49959 (Aug. 29, 2007) (appliance labels); *see also* 75 FR 41696 (July 19, 2010) (light bulb labels); 76 FR 1038 (Jan. 6, 2011) (television labels).

[77] The six hour duty cycle estimate is consistent with ceiling fan research conducted in California. *See* Davis Energy Group (Prepared for Pacific Gas & Electric), Analysis of Standards Options For Ceiling Fans, May 2004 (*http://www.energy.ca.gov/appliances/2003rulemaking/documents/case_studies/CASE_Ceiling_Fan.pdf*). The eleven cent electricity cost figure, which is based on DOE information, also appears on recently amended light bulb labels and television labels. *See* 75 FR 41696 and 75 FR 12470.

[78] *See http://www.energy.ca.gov/2010publications/CEC-400-2010-012/CEC-400-2010-012.PDF.*

[79] 78 FR 17648 (Mar. 22, 2013). The Commission does not propose including energy savings information on the label because it could confuse consumers and would be inconsistent with other FTC energy labels. Nothing in the Rule prohibits manufacturers from making substantiated energy savings claims elsewhere on the package.

[80] The proposed amendment will also have the effect of clarifying that ceiling fan manufacturers must post a copy of their product labels online pursuant to Section 305.6. That section currently directs manufacturers to post their ''EnergyGuide'' labels, and does not specifically mention the current ''Energy Information'' label for ceiling fans. The proposed amendment to Section 305.13 would require ceiling fan manufacturers to use EnergyGuide labels, thereby triggering the online-posting requirement of Section 305.6.

therefore, has not identified a reason to treat the two products similarly.

Finally, the Commission does not propose including disclosures required by the CEC, which include energy information at multiple speeds. Such information is likely to complicate the label by providing three sets of disclosures for CFM, energy cost, and energy use. In addition, the label's current high-speed disclosures should provide adequate information for consumers to compare the relative energy cost and performance of competing fans.[81] The Commission seeks further comment on the proposed label, including its content, and the necessary compliance time for manufacturers.

F. Consolidated Refrigerator Ranges

Background: The current rule organizes refrigerator comparability ranges by configuration (*e.g.,* models with top-mounted freezers), designating eight separate range categories for refrigerators and three for freezers.[82] The ranges disclose the energy costs of the most and least efficient model in each category. These categories allow consumers to compare the energy use of similarly configured units. Specifically, for automatic-defrost refrigerator-freezers, which populate the bulk of showroom floors, the Rule contains five categories (or styles): side-by-side door models with and without through-the-door ice service; top-mounted freezer models with and without through-the-door ice service; and bottom-mounted freezer models.[83]

Comments: AHAM opposed changes to the current range categories, arguing that consolidation of the ranges would cast fully-featured products, which generally use more energy, in an unfavorable light. AHAM also pointed to data suggesting that consumers usually replace their existing refrigerators with similarly configured models. However, AHAM acknowledged that it had no information addressing whether consumers shop with a specific configuration in mind.[84]

The Joint Commenters urged the Commission to consolidate the comparability ranges.[85] They reasoned a single range would allow consumers to easily compare energy performance across models. They argued that the FTC's current approach to refrigerator ranges focuses consumer attention on small differences in energy efficiency and operating costs while obscuring large differences across categories.[86] They also asserted that the current ranges rest on arbitrary classifications devised for purposes other than consumer communication (*e.g.,* implementation of DOE efficiency standards), rather than on any evidence the label classifications are ''likely to assist consumers with their purchasing decisions.'' The Joint Commenters also noted that labels for many models, such as French door refrigerators, have no comparison information at all.

According to the Joint Commenters, many consumers consider refrigerators with different configurations (and likely different features) when making purchasing decisions. To support this assertion, the commenters pointed to data demonstrating that, in 2012, 40% of the visitors to Consumer Reports' online refrigerator ratings reviewed multiple refrigerator-freezer configurations. The Joint Commenters also reasoned that those who examined only one configuration probably considered models with, and without, through-the-door ice dispensers, and may have looked at an additional configuration on a subsequent visit. In addition, the Joint Commenters pointed to AHAM information demonstrating that more than half of side-by-side refrigerator-freezer owners buy replacement units with a different configuration. The commenters contended that this was probably a conservative estimate because it does not include owners who bought similarly configured replacement units with different features. Finally, the Joint Commenters submitted the results of a survey of Earthjustice members showing that more than two thirds of respondents indicated that a label that compared across subcategories would be more likely to assist them in making their purchasing decision.

Finally, the Joint Commenters further argued that, even if some consumers initially limit themselves to a certain product subcategory, an EnergyGuide label illustrating the energy cost range over all subcategories may spur them to consider other configurations. They contend that, although the ENERGY STAR program continues to use separate categories for rating products, ''the mere fact that ENERGY STAR labels refrigerators in a way that obscures the impacts of configurations and features does not justify'' the maintenance of those categories for EnergyGuide labeling.

Discussion: The Commission proposes consolidating most of the ranges for certain types of refrigerator models. The comments suggest that a substantial number of consumers consider different model configurations when shopping. The consolidation of ranges will facilitate such comparison shopping, simplify the range categories, and alert consumers to the relative energy efficiency of various refrigerator types. As the Commission has previously explained, the EnergyGuide label permits consumers to compare the energy costs of competing appliances and to weigh this attribute against other product features in making their purchasing decisions. The Commission expects that consolidation of refrigerator categories will promote this goal by helping consumers to weigh energy cost considerations across different refrigerator configurations.

Specifically, the Commission proposes to consolidate the ranges for refrigerators into three categories: automatic defrost refrigerator-freezers (currently Appendices A4–A8), manual or partial manual refrigerators and refrigerator-freezers (currently Appendices A2–A3, which cover mostly small-sized models), and refrigerators with no freezer (currently Appendix A1). The proposed approach would consolidate ranges for automatic defrost models purchased by the vast majority of residential consumers, while maintaining separate categories for less common models.[87] The Rule would maintain separate size classifications within the three categories because shoppers are unlikely to compare

[81] In limiting the current label's disclosures to high speed operation, the Commission explained that ''inclusion of information for other speed settings would clutter the label with few additional benefits'' and noted comments indicating high-speed measurements reflect the ''the true unregulated performance of the fan.'' 71 FR 78057, 78059 (Dec. 28, 2006).

[82] The Rule further divides each model category into several size classes (*e.g.,* 19.5 to 21.4 cubic feet), each with its own comparability range.

[83] *See* 16 CFR Part 305, Appendices A and B. The Rule also has other range categories for less common models, including those with manual and partial defrost, and refrigerator-only models. In addition, the freezer categories include upright models with automatic defrost, upright models with manual defrost, and chest freezers.

[84] AHAM comments (Sept. 11, 2012) (# 560957–00025) available at *http://www.ftc.gov/os/comments/energylabelamend/560957-0002-84112.pdf.*

[85] Joint Comments (#560957–00015) available at *http://www.ftc.gov/os/comments/energylabelamend/00015-83010.pdf.*

[86] Joint Comments (#563707–00005) available at *http://www.ftc.gov/os/comments/energylabelrangers/index.shtm.*

[87] Given the different characteristics of these latter models, the Commission expects that typical consumers do not consider such models alongside automatic defrost refrigerator-freezers because of significant differences in the performance of these models (*e.g.,* manual defrost vs. automatic defrost). For automatic defrost refrigerator freezers, the label would state, ''Cost range based on all automatic-defrost refrigerator-freezers regardless of features or configuration.''

models of widely different sizes. The proposal also maintains the three freezer categories for upright manual defrost models (Appendix B1), upright automatic defrost models (Appendix B2), and chest freezers (Appendix B3) because there is no evidence that consumers typically compare models across these categories when shopping. Under the proposal, the Commission would require such changes after the receipt of new model data following the implementation of DOE's new standards and test procedures in September 2014.

The Commission seeks comment on this proposal. Among other things, comments should address whether the consolidation of range categories would impact the DOE and EnergyStar programs, which continue to follow DOE's multiple configuration categories.[88]

G. Updates to Heating and Cooling Equipment Labels

Background: On February 6, 2013, the Commission published new labeling requirements for heating and cooling equipment, some of which have been postponed due to ongoing DOE litigation.[89] The new labels, directed by Congress, provide industry members and consumers with information about regional efficiency standards recently issued by DOE.[90] These new DOE requirements impose regional efficiency standards for four product categories: split-system air conditioners, single-package air conditioners, non-weatherized gas furnaces, and mobile home gas furnaces. For all other covered heating and cooling equipment (*e.g.,* oil furnaces, boilers, and electric furnaces), the updated standards remain nationally uniform. The new labels require the inclusion of model number and capacity information on labels for all furnaces and central air conditioners. The Commission explained that this information would help consumers access DOE-generated cost information referenced on the label. In addition, for split systems, the model number and capacity allows consumers to obtain efficiency rating and energy cost information of varying condenser-coil combinations.

In its February 6, 2013 Notice, the Commission tied implementation of the new labeling requirements for all heating and cooling equipment (including products not subject to uniform standards) to the DOE compliance dates for the regional standards.[91] However, as part of ongoing litigation, the DC Circuit Court of Appeals stayed the implementation of the DOE regional furnace standards in 2013.[92] That stay effectively postponed FTC label updates for all furnace products subject to DOE standards, as well as some products, including oil furnaces, boilers, and electric furnaces not subject to the regional standards.

In addition, on April 24, 2014, the Court approved a settlement in the DOE litigation, which vacates and remands DOE's regional standards for non-weatherized natural gas and mobile home furnaces and set a two-year time table for DOE to propose new standards. The settlement does not affect other DOE standards, including the regional standards for split system and single package central air conditioners scheduled to become effective on January 1, 2015. However, as part of the settlement, DOE has agreed to issue a policy statement establishing an 18-month enforcement grace period for any air conditioner units manufactured before January 1, 2015.[93]

Comments: Given the uncertainties raised by the DOE regional standards litigation, AHRI (#563707–00010) urged the Commission to modify the Rule's provisions to establish a new compliance date for boilers and oil-fired furnaces, separate from the regional standards' implementation. These product categories do not have regional standards and are not part of the ongoing DOE litigation. AHRI, therefore, recommended a November 1, 2014 compliance date for boiler and oil furnace disclosures. It also requested that FTC staff provide template labels for these products, consistent with the templates provided for other covered products.[94]

In addition, AHRI (#563707–00010) raised concerns about the required capacity disclosure on the new labels. It explained that, for split-system air conditioners, capacity depends on the actual condenser-coil combination installed on site. The EnergyGuide label only appears on the condensing unit. Because manufacturers cannot predict which coil will be paired with a particular condenser, they cannot predict the system's capacity rating. Similarly, for oil furnaces, the unit's ultimate capacity depends on the input set by the installer.

Thus, in AHRI's view, the inclusion of capacity information on these products is unnecessary and could mislead consumers. In lieu of capacity ratings, AHRI suggested that the FTC allow manufacturers to print basic model numbers on their EnergyGuide labels, which can be used to access cost information on DOE's database.

Discussion: The Commission proposes November 1, 2014 as the effective date for boilers and oil-furnace labels and ranges. Furthermore, because DOE is not likely to issue revised regional furnace standards for at least two years, the Commission proposes to update the labels and ranges for all furnaces consistent with the Commission's February 6, 2013 Notice (see Figures 2 and 3).[95] These updates would not include regional standards information.[96] However, as explained in the 2013 Notice, the updates would include new ranges and a prominent link to an online energy cost calculator provided by a DOE Web site (*productinfo.energy.gov*). This calculator provides a clear, understandable tool to compare energy performance.[97] The Commission also proposes to make these revised labels effective on January 1, 2015 for gas furnaces, to coincide with new efficiency standards for those products. Finally, the Commission seeks comment on whether it should eliminate existing Rule language related to regional furnace standards until DOE issues revised standards in the future.

In response to AHRI's capacity concerns, the Commission proposes eliminating capacity on EnergyGuide labels for heating and cooling

[88] The proposed changes to the ranges would require extensive conforming amendments to sections 305.11, section 305.20, and Appendices A and B. In the interest of brevity, the Commission has not included specific language in this document.

[89] 78 FR 8362.

[90] 16 CFR 305.12 & App. L, Prototype Label 3, Sample Labels 7A, 7B, 9.

[91] DOE scheduled two compliance dates for the new standards: May 1, 2013, for non-weatherized gas furnaces, mobile home gas furnaces, and non-weatherized oil furnaces; and January 1, 2015, for weatherized gas furnaces and all central air conditioners and heat pumps.

[92] *American Public Gas Ass'n* v. *DOE,* No. 11–1485 (D.C. Cir. filed Dec. 23, 2011) (DE.#1433580, May 1, 2013).

[93] *Id.* (DE.# #1489805, April 24, 2014).

[94] *See* FTC templates at *http://www.business.ftc.gov/documents/energyguide-labels-template.*

[95] The proposed rule language in this document contains conforming changes to the range tables for heating and cooling products in Appendices G1 through G8. However, to minimize the length of this document, the proposed rule language does not include conforming changes to all sample labels in the Rule. Should the Commission issue final amendments consistent with this proposal, the final Notice will contain conforming sample label changes.

[96] This proposal would not alter the January 1, 2015 compliance date for central air conditioners established in the February 6, 2013 notice. 78 FR 8362. However, consistent with DOE's enforcement policy for existing stock of central air conditioners (attached to the regional standards settlement), the Commission does not expect manufacturers to place the new regional standards label on units manufactured before January 1, 2015.

[97] 78 FR 8365.

equipment, but maintaining model numbers. As AHRI explained, the installed capacity of many of these products will vary depending, for example, on the condenser-coil combination for split-systems. Accordingly, a capacity requirement raises implementation problems and could mislead consumers. Under the proposal, consumers would be able to use model numbers from the labels to access specific cost information for various products, including condenser-coil combinations, through the DOE Web site. As with other covered products, manufacturers may print multiple model numbers on labels for models sharing the same efficiency ratings. The Commission seeks comment on this proposal.

BILLING CODE 6750–04–P

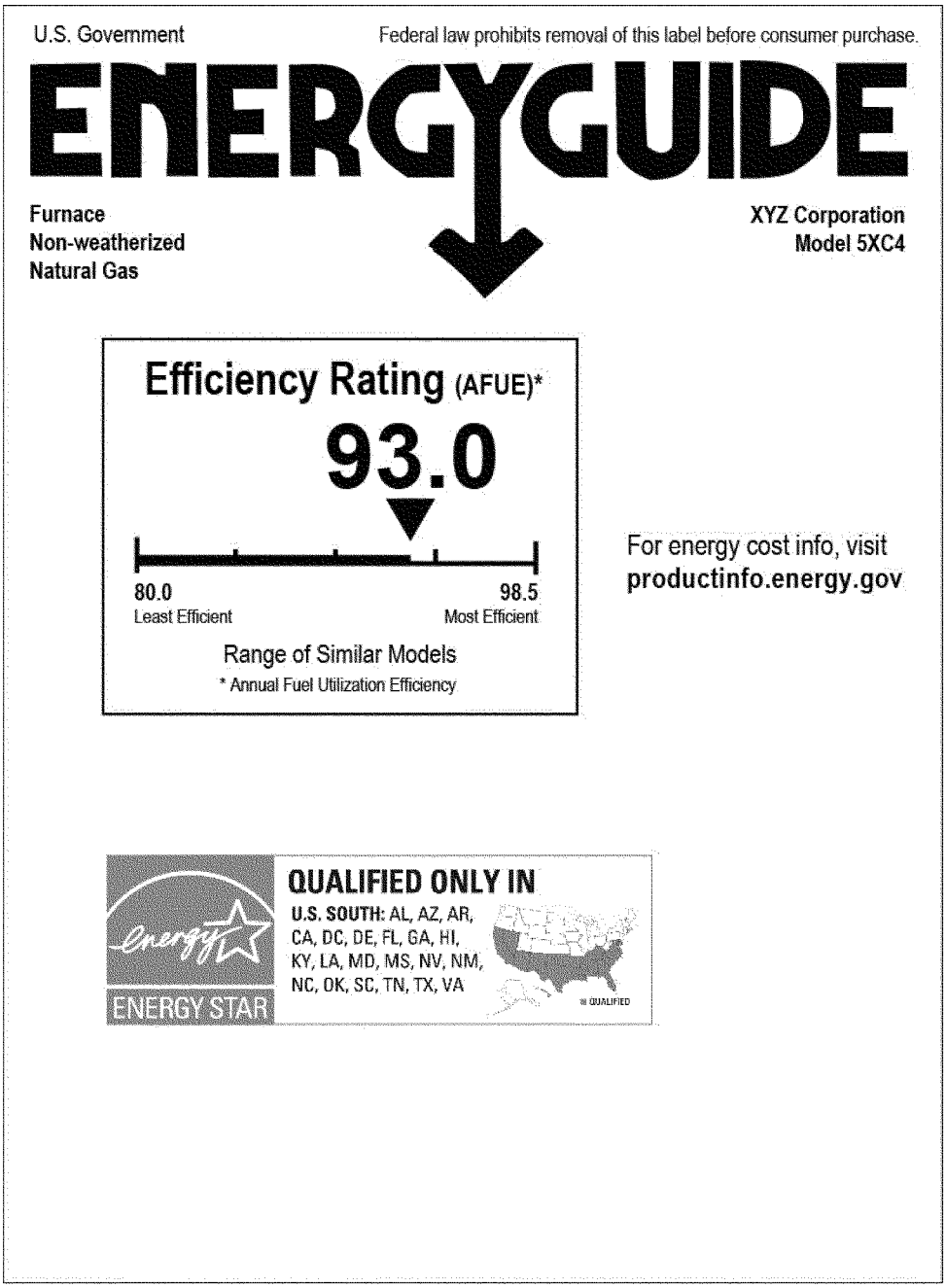


Figure 2 – Proposed Sample Revised Gas Furnace Label For Models Manufactured Before the Effective Date of Regional Standards (ENERGY STAR qualified model)

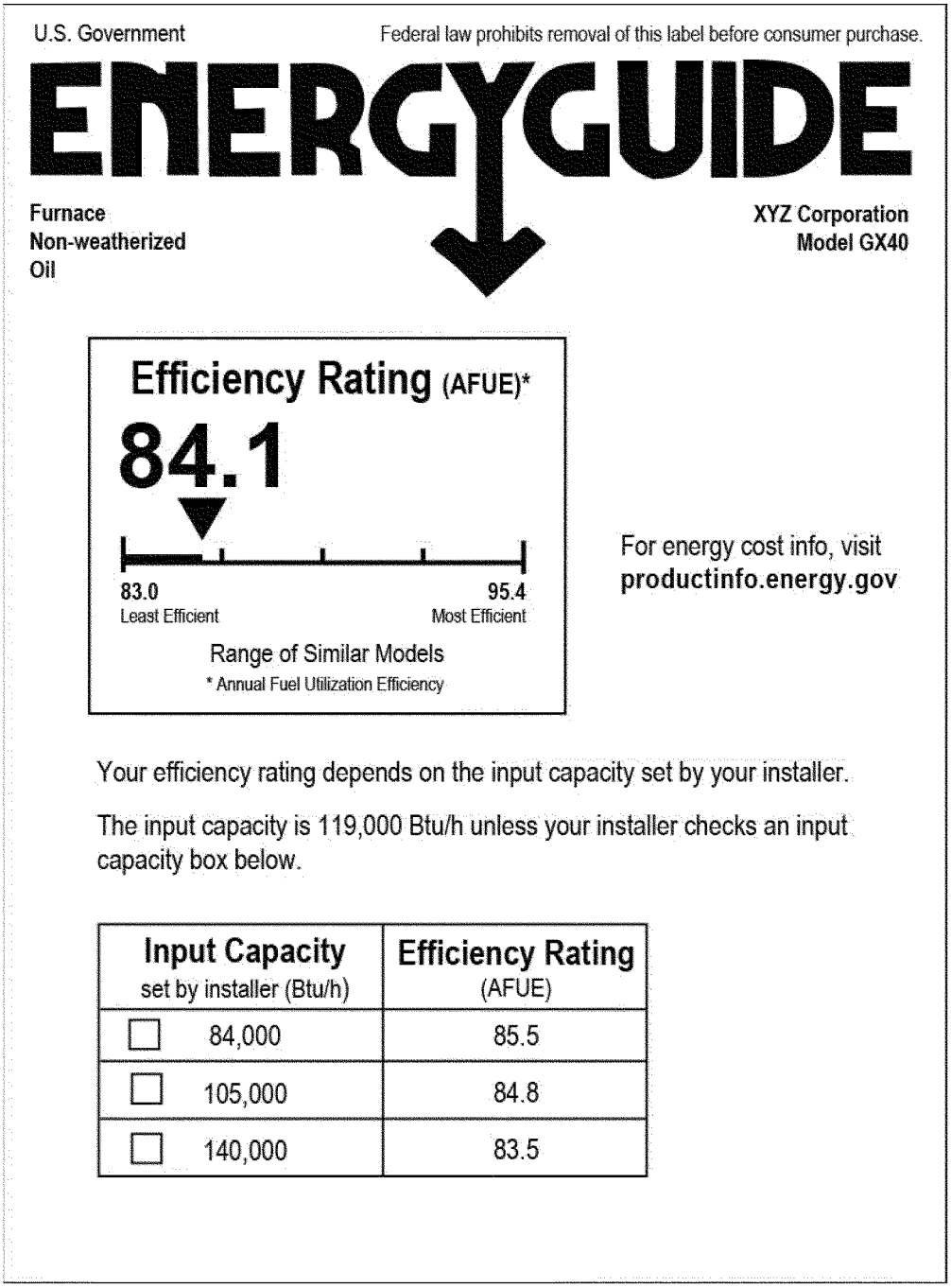


Figure 3 – Proposed Sample Revised Oil Furnace Label For Models Manufactured Before the Effective Date of Regional Standards

BILLING CODE 6750–04–C

H. QR Codes

Background: In the NPRM, the FTC sought comment on whether to require QR (''Quick Response'') codes on EnergyGuide labels. QR codes are black and white matrix barcodes that provide access to a Web site through a mobile phone equipped with scanning software. A QR code could connect consumers to energy use information, including the broad energy impacts and greenhouse gas emissions associated with a product's use, through government Web sites or other source information.

Comments: Most commenters, particularly industry members, raised concerns about the feasibility and utility of the QR code proposal. AHRI (#560957–00020), AHAM (#560957–00020), and A.O. Smith (#560957–00003) warned the codes might inundate consumers with confusing information.[98] AHRI and AHAM added that the EnergyGuide label provides

[98] *See also* Bradford White (# 560957–00004) and BSH (# 560957–00007).

adequate information to consumers, rendering the addition of a QR code, with its associated burden, unnecessary. AHAM further explained that a QR code requirement is premature because DOE has not developed information on broad energy use impacts and greenhouse gas emissions. AHAM also noted the difficulty in judging the efficacy of QR codes without more information about their linked content. Panasonic (# 560957–00014) added that prescriptive rules could be premature for this evolving technology. AHAM and Panasonic also warned that QR codes could create space limitations, particularly for the television label, and diminish the marketing benefits of separate manufacturer created QR codes located elsewhere on the packaging. AHRI urged the Commission to make any QR code optional and to allow manufacturers to link the code to their own Web sites.

In contrast, Southern Cal Edison (#560957–00008) and PG&E (#560957–00009) supported the inclusion of such codes on the label because they would facilitate innovative practices for communicating useful consumer information to help purchasing decisions. In their view, QR codes would complement a growing market trend and allow consumers to conduct ''on the go'' research with their smart phones. It would also provide an opportunity for utility programs and third party rebate programs to inform interested buyers about rebates for efficient products.

The comments also offered differing views on label information for full fuel cycle and greenhouse gas impacts. PG&E urged the FTC to work with DOE to inform consumers about the broad energy impacts and greenhouse gas emissions of covered products and to display such information on the EnergyGuide label. In contrast, Whirlpool asserted that consumers do not find data on greenhouse gases and full fuel cycle information relevant to their purchase decision.

Discussion: The Commission does not propose requiring QR codes on labels. Until the development of Web site content to supplement information already on the EnergyGuide label, it is premature to propose any specific vehicle for linking consumers to that content. For now, manufacturers should not include their own QR codes on the EnergyGuide label, except for the limited purpose of conveying model numbers or similar product identification. Of course, manufacturers may use their own QR codes in other locations.

The FTC staff will continue to consider full-fuel cycle and greenhouse gas information for consumers and keep track of DOE's efforts to incorporate full-fuel cycle analysis into their decisionmaking.[99] To aid that process, the Commission invites comments on these issues, including the overall usefulness of such information in consumer purchasing decisions.

I. Bilingual Issues

Background: The current Rule allows, but does not require, bilingual Lighting Facts labels on packaging for general service light bulbs.[100] The Commission previously sought comment on whether the Rule should mandate non-English labels when manufacturers make claims in a foreign language.[101] Specifically, the Commission asked about the prevalence and content of non-English claims on light bulb packages, the sufficiency of labels in conveying information to non-English speakers, and the impacts of mandatory bilingual labels on packaging.

Comments: NEMA opposed a triggered bilingual labeling requirement, citing space limitations on packages and the confusion multiple languages may cause. NEMA observed that bilingual packaging is common, though not uniform throughout the market, with Spanish and French used most often.[102] The type of information typically conveyed in non-English languages includes performance (lumens, watts), warnings, and application information. According to NEMA, the use of non-English claims depends on the packaging strategies of individual manufacturers and their retail business partners.

NEMA argued that a bilingual label will not fit on all packages and, as a result, a mandatory, triggered bilingual label could discourage manufacturers from providing any bilingual information. In addition, NEMA suggested that a bilingual label may not be necessary for energy labeling because the FTC-required label displays data mostly in numbers.

Discussion: The Commission does not propose mandating bilingual light bulb labels. As discussed in the NPRM, Commission rules and guidance require certain non-English disclosures in advertisements and sales material if the language principally used in such material is not English. For several decades, the Commission has maintained that clear and conspicuous information disclosures mandated by rules, guides, and cease-and-desist orders should be displayed in the language principally used in the advertisement or sales material in question.[103]

The comments offered no evidence that packages for products labeled with the FTC's energy labels convey consumer information principally in a language other than English. Although some packages present information in both English and another language, it appears that English remains the principal language on packaging. Additionally, the prominence of numerical disclosures on the energy labels (*e.g.,* energy cost in dollars) should decrease the need for mandatory bilingual energy labels. The Commission is also concerned that triggered bilingual labels could dissuade manufacturers from providing bilingual information elsewhere on packaging. Accordingly, the Commission does not propose changing the Rule's current requirements. The Commission may revisit this issue should new concerns or information arise.

J. Television Labels Comparison Ranges

Issue: In the January 6, 2013 NPRM, the Commission sought comment on whether to retain energy cost range information on television labels.[104] In earlier comments, the Consumer Electronics Association (CEA) recommended eliminating television ranges, arguing that the data underlying the ranges quickly become obsolete.[105]

[99] *See, e.g.,* 77 FR 49701 (Aug. 17, 2012).

[100] *See* 16 CFR 305.15. EPCA neither mandates nor prohibits multilingual disclosures on labels and packages.

[101] 76 FR 45715 (Aug. 1, 2011).

[102] However, NEMA did not state that any light bulb packaging in the U.S. displays a language other than English as the predominant language.

[103] 16 CFR 14.9 (policy statement entitled, ''Requirements concerning clear and conspicuous disclosures in foreign language advertising and sales materials'') (*see* 38 FR 21494 (Aug. 4, 1973)); *see also* 16 CFR 610.4(a)(3)(ii) (mandatory disclosures about free credit reports must be made in same language as that principally used in the advertisement); 16 CFR 308.3(a)(1) (mandatory disclosures about pay-per-call services must be made in same language as that principally used in advertisement); 16 CFR 455.5 (where used car sale conducted in Spanish, mandatory disclosures must be made in Spanish); 16 CFR 429.1(a) (in door-to-door sales, failure to furnish completed receipt or contract in same language as oral sales presentation is an unfair and deceptive act or practice).

[104] 16 CFR 305.17(f).

[105] CEA comments (May 16, 2012) (#560957–00012) available at *http://www.ftc.gov/os/comments/energylabelamend/560957-00012-83006.pdf.* EPCA grants the Commission discretion to include (or exclude) range information for television labels. 42 U.S.C. 6294(c)(9). However, given recent issuance of a new DOE test procedure, manufacturers must submit energy data whether or not the label displays a range. 42. U.S.C. 6296(b)(4); *see also* 79 FR 19464 (Apr. 9, 2014). CEA also asserted that the FTC labels should serve as the model for energy use disclosures in the North

Continued

As a result, the estimated energy costs for many models fall outside the range depicted on the label, reducing utility. CEA also noted that consumers can rely on other sources, including consumer and trade publications and product reviews, to obtain comparative energy information.

Comments: In response to the January 6, 2013 NPRM, the Joint Commenters (#563707–00005) opposed CEA's recommendation and strongly supported maintaining television ranges. According to the Joint Commenters, EPCA requires the Commission to provide range information on the label and no applicable statutory exemption exists to allow elimination of such information.[106] They further argued that the ranges, even if narrowed due to improved efficiency, still help consumers compare the energy costs of competing recent models and understand that television usage affects energy costs. The Joint Commenters urged the Commission to address perceived problems with television labels by consolidating the range categories or updating the ranges more frequently.

The Joint Commenters also recommended an increase in the size and prominence of the arrow indicating the model's relative location along the comparability range. The arrow denotes placement on the range and allows consumers to quickly gauge whether a model is efficient compared to similar models.

Discussion: The Commission does not propose eliminating the television ranges or otherwise altering the label at this time.[107] The Rule has required the television label for only a few years. It is premature to abandon the ranges without strong evidence supporting such a change and without further experience and information, including updated energy data. In addition, as commenters explained, the ranges continue to provide benefits by illustrating how individual models compare to others on the range, even if efficiency improvements have shifted those ranges somewhat. Likewise, the Commission does not propose enlarging the arrow on the label's comparability range. Unlike other EnergyGuide labels, the TV range graph resembles a thermometer, shaded black up to the point marking the model's energy cost. This graph's depiction, coupled with the arrow, clearly identifies where the model falls on the range. Accordingly, additional graphic enhancements are not necessary.[108]

K. Schedule for Range Revisions

Background: In the NPRM, the Commission sought comment on whether to update range and cost information more frequently than the five years required by 16 CFR 305.10(a). In earlier comments, several energy efficiency organizations suggested that the FTC adopt a three-year schedule to update national average energy cost and the comparison ranges for most products.[109] They also recommended a two-year schedule for products with rapidly changing efficiencies and quicker sell-through periods, such as televisions. These commenters argued that the current schedule fails to keep pace with efficiency improvements. In January 2013, the Commission explained that the five-year schedule strikes a reasonable balance by providing appropriate updates without imposing overly frequent changes that lead to inconsistencies between showroom labels.[110]

Comments: In response to the NPRM, the comments presented conflicting views on the current update schedule. The efficiency groups (#560957–00015) asserted that the five-year schedule results in labels that ''depict a false picture of the market.'' They argued the schedule violates EPCA's directive to include ''information respecting the range of estimated annual operating costs for covered products'' as well as EPCA's requirement that the labels be ''likely to assist consumers in making purchasing decisions.'' [111] They also noted that that FTC annual data collection allows for more frequent updates.[112]

In lieu of the current five-year schedule, the efficiency groups recommended that the Commission update ranges whenever: (1) Multiple new products enter the market in a product subcategory not included in an existing range category, (2) more efficient products appear on the market, and (3) efficiency standards or ENERGY STAR specifications change. In the absence of such thresholds, the Joint Commenters suggested a three-year schedule for most products and a two-year schedule for those with rapidly changing efficiencies and quicker sell-through periods. In addition, to help consumers compare labels bearing different range information, the Joint Commenters recommended the use of the transitional label recently adopted for refrigerators and clothes washers to address range and cost changes.[113] Finally, should the Commission retain the current schedule, the Joint Commenters recommended disclosing the year the range information was collected and lengthening the range's endpoint (*i.e.,* ''most efficient'' model) to provide space on the range for newer, more efficient models introduced in the future.

In contrast, industry commenters supported the current approach. AHAM emphasized the need to minimize frequent label changes because inconsistent cost and range information can lead to consumer confusion and erode consumer confidence in the label. AHAM agreed with the Commission that a five-year schedule appropriately balances the need for consistent disclosures and the need for updates, while minimizing the burdens associated with frequent changes. AHRI argued that any revisions at this point would be premature, because the current schedule has been in place for only a few years. According to AHRI, industry members and consumers have not conveyed any significant concerns to its members about the EnergyGuide label ranges. AHRI further asserted that consumers recognized that the EnergyGuide label serves primarily as a comparative tool. In its view, the label's comparative information does not

American market, including Mexico and Canada. However, CEA did not request that the FTC take any particular action with regard to this issue.

[106] The Joint Commenters argued that ranges for televisions are mandatory under EPCA, citing a provision that requires labels that disclose ''information respecting the range of estimated annual operating costs for covered products to which the rule applies.'' 42 U.S.C. 6294(c)(1). They asserted that, even if FTC were to interpret EPCA as providing authority to eliminate range information, it would be arbitrary to eliminate the range information because FTC has previously acknowledged its value in requiring online retailers to include it among their disclosures. 77 FR 15301.

[107] Contrary to the commenter assertions, EPCA grants the Commission discretion to include (or exclude) range information for television labels. Section 324(c)(9), titled ''Discretionary application,'' clearly states that the Commission may apply range information requirements to labels for certain covered products, including televisions. 42 U.S.C. 6294(c)(9) (''(9) Discretionary application.—The Commission may apply paragraphs (1), (2), (3), (5), and (6) of this subsection to the labeling of any product covered by paragraph (2)(I) or (6) of subsection (a)'').

[108] On April 9, 2014 (79 FR 19464), the Commission announced changes to its Rules, including reporting requirements, to conform to a new DOE test procedure. After the Commission reviews the new data, it will consider issuing updated comparability ranges for television labels.

[109] Joint Comments from Energy-Efficiency and Consumer Organizations (May 16, 2012) (#560957–00015).

[110] *See* 78 FR 1779, 1781 (Jan. 6, 2013).

[111] *See* 42 U.S.C. 294(c)(1)(B) and 6294(c)(3).

[112] *See* 16 CFR 305.8. The groups also criticized the timing of the Commission's most recent round of updates (announced in 2012 and finalized in 2013) and delays to range and cost updates pending DOE test procedure changes for refrigerators, clothes washer, and furnaces.

[113] 78 FR 43974 (July 23, 2013).

change so dramatically over a five-year period that it warrants more frequent label changes. It also suggested that consumers understand the need to consider local energy costs when weighing home heating and cooling equipment purchases. Thus, fuel rate changes do not offer a reason to revise labels more frequently.

Discussion: The Commission is not proposing changes to the update schedule for comparability ranges and fuel rates. In establishing the current five-year schedule, the Commission sought to strike a balance between maintaining consistent labels and providing updates to cost and range information. Though there are benefits to more frequent updates, the transition periods between such updates create inconsistent labels in the market, which can cause confusion, hamper comparison shopping, and reduce confidence in the label.[114]

The current five-year interval ranges is consistent with past trends in market data. Over the years, model energy use has not always changed significantly from year to year across all product types and the product range endpoints have not always moved toward higher efficiency levels from year to year.[115] For example, before 2007, the Commission reviewed model data every year and revised the ranges if they deviated 15% or more from the previous year. Using this approach, the Commission generally updated product ranges at about five-year intervals.[116]

In addition, frequent fuel cost updates for the label can significantly impact label information during transition periods, making it difficult for consumers to compare new and old labels. Frequent fuel cost updates not only alter the range information but also the product's energy cost (the label's primary energy disclosure), and can inhibit comparisons with older labeled products generated with previous fuel rates.

Though the Commission does not propose to alter the current schedule, the Rule gives the Commission discretion to change ranges and fuel rates more frequently. If parties identify ranges or fuel rate information that should be updated before the five-year period ends, they should alert the Commission so that it may consider whether to update the range.[117]

Finally, the Commission declines to adopt the recommendation to change ranges whenever a more efficient product enters the market, whenever DOE standards or test procedures change, or whenever a new product subcategory (*e.g.,* a new refrigerator model type) enters the market. Doing so could lead to unnecessary updates and associated confusion during transition periods. Specifically, a trigger based on the introduction of more efficient products might yield insignificant range changes in cases where a single, slightly more efficient product arrives on the market. In addition, DOE test procedure amendments do not always yield significant changes in measured energy use. Lastly, new product subcategories do not necessarily warrant range changes because such new products may have little market presence or may have energy costs within existing ranges.[118]

L. Retailer Responsibility

Background: Currently, the Rule prohibits retailers from removing labels or rendering them illegible,[119] but does not otherwise require retailers to display labels at the points-of-sale. In 2011, when the Commission issued new label requirements for televisions, it declined to impose new retailer obligations, noting that the amendments for labels (both in stores and online) created a network of measures calculated to keep labels attached and visible on display models.[120] The Commission, however, expressed willingness to revisit the issue at a later date.

Comments: In response to the 2012 regulatory review notice, the Joint Commenters (#560957–00028) urged the Commission to hold retailers responsible for ensuring the label's presence on covered products sold in their stores. Their year long investigation found that labels on 55% of the appliances they observed were either missing, detached, obstructed, or otherwise not affixed in accordance with the Rule. They also found that, despite the Commission's recent measures to ensure the presence of television labels in showrooms, 50% of the televisions observed were missing labels. Accordingly, they recommended that the Commission hold retailers responsible for ensuring that labels are present on the products they sell.

The Joint Commenters further opined that compliance with such a requirement is feasible. They argued that retailers would not face extraordinary obstacles matching EnergyGuide labels with the intended products, noting that retailers already manage point-of-sale materials for specific products, such as price and rebate information and Energy Star labels. Additionally, the Joint Commenters observed during site visits that some retailers appear to attach, reattach, or reprint missing labels. Indeed, the Joint Commenters argued that retailers are better situated than manufacturers to remedy lost, missing, or non-compliant labels. In addition, citing a ''preliminary analysis'' of their investigative results, they argued that the identity of the retailer is most closely correlated with the rate of label compliance.

AHAM also encouraged the Commission to address retailer responsibility, although it stopped short of supporting a new mandate (#563707–00003). AHAM explained that manufacturers lose control over products after they leave the factory, and that retailers own the products they sell to consumers. Accordingly, AHAM argued that manufacturers should not be held responsible for missing labels on showroom floors.

Discussion: The Commission plans to pursue improvements in label design to

[114] *See* 72 FR 49948, 49959 (Aug. 29, 2007) (discussing potential problems associated with frequent updates). In the past, the Commission has issued routine range updates without seeking comments. *See, e.g.,* 67 FR 65310 (Oct. 24, 2002). However, as noted by commenters, the Commission has recently delayed range updates for several products types to synchronize new range and cost updates with other ongoing regulatory changes and avoid multiple label changes in a short time period. For example, the Commission coupled new ranges for dishwashers, room air conditioners, and water heaters with several label content changes, which required an opportunity for comment and thus additional time to promulgate. 78 FR 43974 (July 23, 2013). In addition, the Commission plans to issue new ranges for refrigerators and clothes washers when the new DOE standards and test procedures become effective to avoid publishing short-lived ranges based on many models likely to become obsolete with the arrival of the new DOE standards. 78 FR 8362 (Feb. 6, 2012).

[115] For example, from 2007 to 2012, the range for standard-size clothes washers changed year to year as follows (normalized using 12 cents per kWh): $11–$80 (2007), $13–$60 (2008), $10–$75 (2009), $9–$74 (2010), $9–$60 (2011), and $10–$61 (2012).

[116] 72 FR 49952.

[117] The comments also suggest that the Commission deploy labels with special language to mitigate confusion during these transition periods. Although the Commission has created such labels in extraordinary circumstances (*e.g.,* 78 FR 43974 (July 23, 2013) (refrigerator and clothes washer transition labels in response to significant changes to DOE test procedures and standards)), frequent use of such ''transitional'' labels is likely to lead to multiple versions of such labels in the market and ultimately result in substantial confusion.

[118] The Commission does not propose to include the range's date on the label. Indeed, the Commission recently amended the rule to eliminate references to fuel rate vintage on the label, explaining that such disclosures could cause confusion. For instance, a ''2007'' reference to a range or fuel rate on the label may incorrectly suggest to some consumers that the product itself was produced in 2007. *See* 43 FR 7843976. In addition, the Commission does not propose adding space to the label's range bar to reserve room for more efficient models because such a change to the range scale could be confusing to consumers.

[119] 16 CFR 305.4(a)(2).

[120] 76 FR 1038, 1047 (Jan. 6, 2011).

increase label presence on showroom display models—as discussed in Section C of this document—before pursuing new responsibilities for retail stores. Recent store visits by FTC staff indicate that the new television labels, which must be adhesive, are more likely to remain on showroom models than labels on appliances. During the Spring of 2013, FTC staff observed more than 2,300 on-display televisions in 42 stores of six national retailers across nine regions.[121] In contrast to the Joint Commenters' earlier findings, 81% of models displayed had labels present.[122] Although FTC staff found that label presence varied across the retail stores visited, the variability between the observed retail chains was not large: between 75% and 87%. These findings suggest that improvements in label design and attachment methods alone, which the Commission now proposes for appliances (see Section II.C.), may be effective in significantly improving label presence.

Retailers, however, can play an important role in ensuring that labels appear on covered products at the points-of-sale. Even if retailers do not create the labels, they can identify missing or obscured labels in their showrooms and replace them. Moreover, although label design and attachment improvements can raise the rate of label presence, they cannot guarantee it.[123] At the same time, the burden on retailers of ensuring label presence may exceed the benefits. An affirmative retailer duty would require retailers stores to monitor product displays. Where labels are missing from display models, the retailer would have to find a properly-labeled replacement or obtain a substitute label. During the television rulemaking, the Consumer Electronics Retailers Coalition argued that requiring retailers to reaffix missing labels would cause ''chaos,'' because retailers would be unable to quickly match labels with products, increasing the risk of inaccurate labeling.[124]

It is premature to impose these costs and incur these risks when better label requirements and greater availability of online labels may alleviate the problem. The Commission, therefore, seeks further comment, particularly on improved label design and other approaches that could reduce the incidence of missing labels.

M. Marketplace Web Sites

Background: The March 15, 2012 NPRM proposed requiring retail Web sites to display the full EnergyGuide or Lighting Facts label online. In January 2013, the Commission published final amendments to the Rule's catalog provision, requiring Web site sellers to display the label—either in full or as a logo icon with a hyperlink—for most covered products.[125] This requirement applies to ''[a]ny manufacturer, distributor, retailer, or private labeler who advertises a covered product on an Internet Web site in a manner that qualifies as a catalog under this Part.'' [126] The Rule defines ''catalog'' as ''printed material, including material disseminated over the Internet, which contains the terms of sale, retail price, and instructions for ordering, from which a retail consumer can order a covered product.'' [127]

These amendments do not cover marketplace Web sites that serve as platforms for facilitating online product purchase by performing functions such as hosting sellers' advertising, matching buyers' searches to sellers' products, and processing payment and shipment directions.[128] A marketplace Web site may not fit the definition of ''retailer'' or ''distributor'' in the Rule if, for example, it does not take delivery or sale of the consumer products advertised and sold on its online platform. The Rule does not require such marketplace Web sites to either display or ensure the display of labels for covered products sold by third parties to consumers through their platforms. However, the Rule continues to apply to those third parties (retailers, manufacturers, distributors, and private labelers) that sell their products on such marketplace Web sites. The Rule also applies to the marketplace Web sites if they sell products as retailers through their own Web sites.[129]

Comments: The Joint Commenters (#560957–00028) urged the Commission to amend the Rule to address marketplace Web sites. The Joint Commenters presented several arguments for this proposal. First, they contend that noncompliance with the Rule's labeling requirements is ''rampant'' on marketplace Web sites.[130] Second, they argued that marketplace Web sites exercise ultimate control over the listings for products sold by third party sellers on their platforms, and should therefore be responsible for ensuring labeling. According to the Joint Commenters, marketplace Web sites generally require sellers to allow them to make any modifications to the listing, or remove it altogether, as a condition of selling products on their platforms. Sellers may submit proposed content (including price and shipping information) or seek removal of the listing, but the marketplace Web sites retain final authority over what appears in the listing. Third, the Joint Commenters argued that in light of marketplace Web sites' substantial control over listings, they are capable, if not best situated, to ensure label compliance for the products on their platforms. They noted that some marketplace Web sites already police other types of labeling and require listing preapproval for particular product categories. Therefore, they can

[121] Although the staff visited a variety of stores and locations, the results of these visits are not necessarily nationally representative.

[122] Another one percent had a label that was not properly affixed or was otherwise unreadable.

[123] EPCA authorizes the Commission to ''prescribe labeling rules under this section applicable to all covered products,'' including rules governing label disclosures ''at the point of sale.'' *See* 42 U.S.C. 6294(a)(1),(c)(3), and (c)(4); *see also* 42 U.S.C. 6298 (authorizing the Commission to issue rules it ''deems necessary to carry out'' the law's provisions). The Commission imposes upon retailers affirmative obligations to display labels to customers for particular product categories. *See, e.g.,* 16 CFR 305.14(b)(2)(ii) (requiring retailers to show consumers the labels for covered central air conditioners, heat pumps, or furnaces prior to purchase); 16 CFR 305.19 (requiring retailers to make written disclosures at point-of-sale).

[124] *See* 76 FR 1047 (Jan. 7, 2011).

[125] *See* 78 FR 2209 (amending 16 CFR 305.20; effective January 15, 2014). A limited set of covered products—showerheads, faucets, water closes, urinals, general service fluorescent lamps, fluorescent lamp ballasts, and metal halide lamp fixtures—can disclose specified information instead of displaying the EnergyGuide or Lighting Facts label. *See id.* (amending 16 CFR 305.20(a)(ii)).

[126] 16 CFR 305.20(a).

[127] 16 CFR 305.2(h).

[128] EPCA states that if a ''manufacturer or any distributor, retailer, or private labeler of such product advertises such product in a catalog from which it may be purchased, such catalog shall contain all information required to be displayed on the label, except as otherwise provided by rule of the Commission.'' 42 U.S.C. 6296(a). EPCA defines a ''retailer'' as ''a person to whom a consumer product is delivered or sold, if such delivery or sale is for purposes of sale or distribution in commerce to purchasers who buy such product for purposes other than resale,'' and a ''distributor'' as ''a person (other than a manufacturer or retailer) to whom a consumer product is delivered or sold for purposes of distribution in commerce.'' It defines ''manufacturer'' as ''any person who manufactures a consumer product,'' and ''private labeler'' as ''an owner of a brand or trademark on the label of a consumer product, which bears a private label.'' 42 U.S.C. 6291(12)–(15). The Rule's definitions of ''manufacturer,'' ''distributor,'' ''retailer,'' and ''private labeler'' are consistent with EPCA's definitions. *See* 16 CFR 305.2.

[129] Taking physical possession of the product would likely render the marketplace Web site a ''retailer'' or ''distributor'' under EPCA and the Rule. *See* fn. 128, *supra.* Therefore, a product's delivery to a marketplace Web site's warehouse for temporary storage before proceeding in shipment to the consumer may trigger the marketplace Web site's responsibility for displaying the product's label online under the current Rule.

[130] They presented findings from 2011 and 2012 product searches on two prominent marketplace Web sites, demonstrating noncompliance of over 90%.

play the same gatekeeping function with energy labeling. Fourth, the Joint Commenters argued that it makes little sense to hinge liability for labeling compliance on whether a marketplace Web site takes delivery of a product. This distinction, according to the commenters, is irrelevant to EPCA's purpose of assisting consumers in making purchasing decisions. Finally, the Joint Commenters argued that neither EPCA nor the Communications Decency Act (''CDA'') prohibits the creation of a separate requirement for marketplace Web sites.[131]

The Joint Commenters also requested that the Commission clarify that (i) the Rule applies to sellers who list covered products for sale on Web site catalogs, but do not take physical possession of products, and (ii) the Rule's term ''catalog'' includes: online product listings that require an additional click or mouse-over to reveal the product's retail price; product Web pages that allow the consumer to select different product options, such as color, before moving on to complete the purchase; and marketplace Web site listings that contain the terms of sale, retail price, and instructions for ordering, but that require consumers to click through to another Web site to complete the order.

Discussion: The Commission is not proposing additional marketplace Web site requirements.[132] The Rule already requires retailers, manufacturers, distributors, and private labelers that sell covered products on marketplace Web sites to display labels for those products. Therefore, an additional requirement aimed at marketplace Web sites would create a secondary layer of coverage. To be sure, such added coverage may improve the availability of label information to consumers. But it is not clear whether that potential benefit to consumers outweighs the potential burdens on marketplace Web sites, such as monitoring label presence and/or compliance. To aid its efforts to improve the Rule in the future, the Commission seeks further comments on the need for, and the burdens and benefits of, requiring marketplace Web sites to ensure label display for products sold on their platforms. Comments should address the current state of affairs for label presence among marketplace Web sites, the projected consumer benefits of requiring marketplace Web sites to ensure label display on their platforms, the projected costs, and the anticipated impact of this document's proposed requirement to list all electronic label images for public display on the DOE's CCMS online database.

N. Clothes Dryer Labels

Background: When the Commission initially issued the energy labeling requirements in the 1979 Rule, it declined to label dryers, citing their limited annual energy cost range.[133] At that time, the maximum annual energy cost difference between dryers was only $5. Therefore, the Commission concluded that the costs of testing and labeling would ''far outweigh the potential benefits'' of labeling.[134]

Comments: The Joint Commenters (#563707–00005) urged the Commission to require clothes dryer labels because three basic requirements for labeling now exist. First, DOE has established a test procedure. Second, clothes dryer labeling is ''just as economically and technically feasible as labeling other white goods, such as clothes washers, dishwashers and refrigerators.'' Finally, clothes dryer labels will assist consumers in making purchasing decisions. Specifically, the commenters explained that labeling will help consumer decisions because clothes dryers use significantly more energy than the majority of products in the labeling program, including about two to three times the energy as clothes washers. In addition, in their view, the absence of dryer labels creates the misimpression that dryer energy use is not significant. The commenters argued that a dryer label would help consumers by leading some to forgo or delay a dryer purchase (or washer and dryer) and instead hang-dry their clothes or use a laundromat; choose a less expensive unit to offset the energy costs; or use their dryer more efficiently. They also suggested that labels will help consumers by revealing significant energy cost differences between gas and electric models.

The Joint Commenters acknowledged the small difference in energy costs between similar dryer models. However, they noted recent DOE amendments associated with an updated test procedure suggest a broader range of energy use among dryers than previously thought. In addition, the adoption of heat-pump dryers will lead to significantly more efficient models in the future. In both absolute and relative terms, they predicted efficiency differences among clothes dryer models will be greater than efficiency differences among existing subcategories for televisions and refrigerators.

Alliance Laundry Systems (#563707–00012) disagreed, arguing that the FTC should not require labels for a covered product simply because it uses large amounts of energy. Alliance explained that the range of energy use among competing dryers is narrow. Thus, labels would not aid consumer purchasing decisions. The Alliance also noted that the high purchase price for the new heat-pump clothes dryers will discourage consumers from purchasing such products even if they are more efficient than other models.

Discussion: The Commission is not proposing to require labels for clothes dryers at this time. Recent DOE dryer information suggests that dryer efficiency varies little across available models. In fact, DOE testing indicates the difference in annual energy costs between the most efficient and least efficient electric models currently available is at most $11 per year.[135] Although electric dryers using heat-pump technology will be more efficient than current models, few, if any, such models are currently available in the U.S.[136]

Absent meaningful variation in energy usage, the Commission doubts that labeling would significantly aid consumer choices. Although some comments suggest that labels could induce consumers to hang dry their

[131] The CDA provides that ''[n]o provider or user of an interactive computer service shall be treated as the publisher or speaker of any information provided by another information content provider.'' 47 U.S.C. 230(c).

[132] In addition, the Commission is not proposing changes to the catalog provisions because it is not clear such amendments are necessary to improve current requirements. Indeed, as part of the regulatory review, the Commission (78 FR 2200 (Jan. 10, 2013)) recently amended the Rule to require online retailers to post the labels ''clearly and conspicuously and in close proximity to the covered product's price on each Web page that contains a detailed description of the covered product and its price.'' 16 CFR 305.20(a)(2).

[133] Under EPCA, the Commission must prescribe labels for dryers unless it finds labeling would not be technologically or economically feasible. 42 U.S.C. 6294(a)(1).

[134] 44 FR 66469 (Nov. 19, 1979).

[135] *See* U.S. DOE, *Technical Support Document (TSD) for Energy Conservation Program: Energy Conservation Standards for Residential Clothes Dryers and Room Air Conditioners;* Direct Final Rule TSD, Table 8.2.26, available at *http://www.regulations.gov/#!documentDetail;D=EERE–2007–BT–STD–0010–0053.* The table indicates that the difference in annual energy use between the baseline model and the most efficient non-heat-pump dryer is 89 kWh. At energy prices of $0.12 per kWh, this is approximately $11 per year. Considering inflation, this spread is even smaller than the cost range identified by the Commission in 1979. In addition, DOE's data suggests that annual operating costs for these dryers is generally lower than $80.

[136] Further, while not dispositive to Commission's decision, we note that both heat-pump models and more efficient conventional models are significantly more expensive to manufacture and install. DOE estimates that, based on current costs, it would take decades (surpassing the likely product life) for the energy savings from an efficient dryer to cover its higher purchase price. TSD, Tables 8.3.1–8.3.6.

clothes, it seems unlikely that labels will convince many consumers, already shopping for a clothes dryer, to hang dry their clothes instead of making a purchase. In addition, although a label would disclose the dryer's energy cost in absolute terms and perhaps illustrate the relative cost of different fuels, there is no evidence that such information would impact consumer decisions to purchase a model using a particular fuel type. Accordingly, consistent with the Commission's earlier conclusion with regard to dryers, labeling costs are likely to outweigh benefits to consumers. However, heat-pump or other more efficient electric dryers may become available in the U.S. market and offer a broader range of energy efficiency. In addition, as suggested by commenters, changes to the DOE test procedure may reveal greater differences among models not demonstrated by current testing methods. Should these or other developments occur, the Commission may revisit the issue.

O. Plumbing Products

The Commission proposes two minor changes related to plumbing products. First, it proposes amendments to clarify that retail Web sites may hyperlink to flow rate information for the covered plumbing products they sell. Recent amendments to Section 305.20 allow online retailers to use a hyperlink to connect consumers to EnergyGuide and Lighting Facts labels for specific products, but do not specify how online sellers may link to required plumbing disclosures.[137] The proposed amendment would allow sellers to connect consumers to flow rate information using a hyperlink labeled ''Water Usage.''

Second, the Commission proposes routine conforming changes to the Rule in response to DOE test procedure changes. On October 23, 2013, DOE announced changes to the testing procedures for residential plumbing products and amended some product definitions.[138] In response, the Commission proposes a conforming change to the definition of ''showerhead'' in Part 305.

III. Request for Comment

You can file a comment online or on paper. For the Commission to consider your comment, we must receive it on or before August 18, 2014. Write ''Energy Labeling Regulatory Review (16 CFR Part 305) (Matter No. R611004)'' 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 public Commission Web site, at *http://www.ftc.gov/os/publiccomments.shtm.* As a matter of discretion, the Commission tries to remove individuals' home contact information from comments before placing them on the Commission Web site.

Because your comment will be made public, you are solely responsible for making sure that your comment does not include any sensitive personal information, such as anyone'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 that your comment does not include any sensitive health information, such as medical records or other individually identifiable health information. In addition, do not include any ''[t]rade secret or any commercial or financial information which is . . . privileged or confidential,'' as discussed in § 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). In particular, do not include competitively sensitive information such as costs, sales statistics, inventories, formulas, patterns, devices, manufacturing processes, or customer names.

If you want the Commission to give your comment confidential treatment, you must file it in paper form, with a request for confidential treatment, and you have to follow the procedure explained in FTC Rule 4.9(c), 16 CFR 4.9(c). Your comment will be kept confidential only if the FTC General Counsel, in his or her sole discretion, grants your request in accordance with the law and the public interest.

Postal mail addressed to the Commission is subject to delay due to heightened security screening. As a result, we encourage you to submit your comments online. To make sure that the Commission considers your online comment, you must file it at *https://ftcpublic.commentworks.com/ftc/energyguidereview,* by following the instruction on the web-based form. If this document appears at *http://www.regulations.gov,* you also may file a comment through that Web site.

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 B), Washington, DC 20580, or deliver your comment to the following address: Federal Trade Commission, Office of the Secretary, Constitution Center, 400 7th Street SW., 5th Floor, Suite 5610 (Annex B), Washington, DC 20024. If possible, submit your paper comment to the Commission by courier or overnight service.

Visit the Commission Web site at *http://www.ftc.gov* to read this document and the news release describing it. 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 August 18, 2014. You can find more information, including routine uses permitted by the Privacy Act, in the Commission's privacy policy, at *http://www.ftc.gov/ftc/privacy.htm.*

Because written comments appear adequate to present the views of all interested parties, the Commission has not scheduled an oral hearing regarding these proposed amendments. Interested parties may request an opportunity to present views orally. If such a request is made, the Commission will publish a document in the **Federal Register** stating the time and place for such oral presentation(s) and describing the procedures that will be followed. Interested parties who wish to present oral views must submit a hearing request, on or before July 8, 2014, in the form of a written comment that describes the issues on which the party wishes to speak. If there is no oral hearing, the Commission will base its decision on the written rulemaking record.

IV. Paperwork Reduction Act

The current Rule contains recordkeeping, disclosure, testing, and reporting requirements that constitute information collection requirements as defined by 5 CFR 1320.3(c), the definitional provision within the Office of Management and Budget (OMB) regulations that implement the Paperwork Reduction Act (PRA). OMB has approved the Rule's existing information collection requirements through May 31, 2017 (OMB Control No. 3084 0069). The proposed amendments make changes in the Rule's labeling requirements that will increase the PRA burden as detailed below.[139]

[137] 78 FR 2200 (Jan. 10, 2013).

[138] 78 FR 62970 (Oct. 23, 2013).

[139] Several proposed labeling changes, including changes to label attachment methods, refrigerator ranges, URL links for labels, ceiling fan labels, and room air conditioners, should impose no additional burden beyond existing estimates because such changes either impose no or *de minimis* additional burdens or manufacturers should be able to

Accordingly, the Commission will submit this Notice of proposed rulemaking and associated Supporting Statement to OMB for review under the PRA.[140]

Package and Product Labeling (expanded lamp coverage): The proposed amendments require manufacturers to label several new bulb types. Accordingly, manufacturers will have to amend their package and product labeling to include new disclosures. The new requirements impose a one-time adjustment for manufacturers. The Commission estimates that there are 50 manufacturers making approximately 3,000 of these newly covered products. This adjustment will require an estimated 600 hours per manufacturer on average.[141] Annualized for a single year reflective of a prospective 3-year PRA clearance, this averages to 200 hours per year. Thus, the label design change will result in cumulative annualized burden of 10,000 hours (50 manufacturers × 200 hours). In estimating the associated labor cost, the Commission assumes that the label design change will be implemented by graphic designers at an hourly wage rate of $23.85 per hour based on Bureau of Labor Statistics information.[142] Thus, the Commission estimates annual labor cost for this adjustment will total $238,500 (10,000 hours × $23.85 per hour).

Labeling (portable air conditioners): The proposed amendments require manufacturers to create and affix labels on these portable products.[143] The amendments specify the content, format, and specifications of the required labels. Manufacturers would add only the energy consumption figures derived from testing and other product-specific information. Consistent with past assumptions regarding appliances, FTC staff estimates that it will take approximately six seconds per unit to affix labels. Staff also estimates that there are 1,000,000 portable air conditioner units distributed in the U.S. per year. Accordingly, the total disclosure burden per year for refrigeration products would be 1,667 hours (1,000,000 × 6 seconds). Assuming that product labels will be affixed by electronic equipment installers at an hourly wage of $23.50 per hour, cumulative associated labor cost would total $39,175 per year.

Testing (expanded lamp coverage): The Commission assumes conservatively that manufacturers will have to test 3,000 basic light bulb models out of an estimated 6,000 covered products. The Commission also assumes conservatively that testing will require 14 hours for each model for a total of 42,000 hours. In calculating the associated labor cost estimate, the Commission assumes that this work will be implemented by electrical engineers at an hourly wage rate of $44.89 per hour. Thus, the Commission estimates that the proposed label design change will result in associated labor costs of approximately $1,885,380 (42,000 hours × $44.89 per hour).

Testing (portable air conditioners): Manufacturers need not test each basic model annually; they must retest only if the product design changes in such a way as to affect energy consumption. Staff believes that the frequency with which models will be tested every year ranges roughly between 10% and 50%. It is likely that only a small portion of the tests conducted will be attributable to the proposed Rule's requirements. Nonetheless, given the lack of specific data on this point, the Commission conservatively assumes that all of the tests conducted would be attributable to the Rule's requirements and will apply to that assumption the high-end of the range noted above for frequency of testing. Based on an informal review of products offered on Web sites as well as consultation with DOE staff, staff estimates that there are approximately 150 basic models, that manufacturers will test two units per model, and that testing would require one hour per unit tested. Given these estimates and the above-noted assumption that 50% of these basic models would be tested annually, testing would require 150 hours per year. Assuming further that this testing will be implemented by electrical engineers, and applying an associated hourly wage rate of $44.89 per hour, labor costs for testing would total $6,734.

Recordkeeping (expanded lamp coverage): Pursuant to Section 305.21 of the proposed amended Rule, manufacturers must keep test data on file for a period of two years after the production of a covered product model has been terminated. Assuming one minute per model and 3,000 basic models, the recordkeeping burden would total 50 hours. Assuming further that these filing requirements will be implemented by data entry workers at an hourly wage rate of $15.28 per hour, the associated labor cost for recordkeeping would be approximately $764 per year.

Recordkeeping (portable air conditioners): Pursuant to Section 305.21 of the proposed amended Rule, manufacturers must keep test data on file for a period of two years after the production of a covered product model has been terminated. Assuming one minute per model and 150 basic models, the recordkeeping burden would total 3 hours, rounded upward. Assuming further that these filing requirements will be implemented by data entry workers at an hourly wage rate of $15.28 per hour, the associated labor cost for recordkeeping would be approximately $46 per year.

Reporting Requirements (portable air conditioners): In addition, the proposed labeling for these products would increase the Rule's reporting requirements. Staff estimates that the average reporting burden for these manufacturers is approximately two minutes per basic model to enter information into DOE's online database. Based on this estimate, multiplied by an estimated total of 150 basic portable air conditioners models, the annual reporting burden for manufacturers is an estimated 5 hours (2 minutes × 150 models ÷ 60 minutes per hour). Assuming further that these filing requirements will be implemented by data entry workers at an hourly wage rate of $15.28 per hour, the associated labor cost for recordkeeping would be approximately $76 per year. Any non-labor costs associated with the reporting amendments are likely to be minimal. The Commission does not expect that the proposed amendments for portable air conditioners will create any capital or other non-labor costs for such testing.[144]

Catalog Disclosures (expanded light bulb coverage and portable air conditioners): The proposed amendments would require sellers

incorporate the proposed changes into their normally scheduled package or label revisions.

[140] The PRA analysis for this rulemaking focuses strictly on the information collection requirements created by and/or otherwise affected by the amendments. Unaffected information collection provisions have previously been accounted for in past FTC analyses under the Rule and are covered by the current PRA clearance from OMB.

[141] The Commission has increased its estimate of the hours required to make this change from earlier estimates given recent concerns raised about the burden of implementing label changes. *See* 75 FR 81943 (Dec. 29, 2010).

[142] The above mean hourly wage and those that follow are drawn from Bureau of Labor Statistics, U.S. Department of Labor, Occupational Employment and Wages—May 2013, Table 1 (National employment and wage data from the Occupational Employment Statistics survey by occupation, May 2013), available at: *http://www.bls.gov/news.release/ocwage.t01.htm.*

[143] Though the Rule allows manufacturers to incorporate the label onto their packaging (a less expensive labeling method), the Commission, for the purposes of this analysis, assumes conservatively that manufacturers will affix individual labels to packaging.

[144] There are no proposed reporting requirements for the expanded light bulb coverage.

offering covered products through catalogs (both online and print) to disclose energy use for each light bulb and portable air conditioner model offered for sale. Because this information is supplied by the product manufacturers, the burden on the retailer consists of incorporating the information into the catalog presentation. FTC staff estimates that there are 200 online and paper catalogs for these products that would be subject to the Rule's catalog disclosure requirements. Staff additionally estimates that the average catalog contains approximately 100 such products and that entry of the required information takes one minute per covered product. The cumulative disclosure burden for catalog sellers is thus 1,000 hours (200 retailer catalogs × 300 products per catalog × 1 minute each per product shown). Assuming that the additional disclosure requirement will be implemented by data entry workers at an hourly wage rate of $15.28, associated labor cost would approximate $15,280 per year.

Estimated annual non-labor cost burden (expanded lamp coverage): The Commission estimates that the annualized capital cost of expanding the light bulb label coverage is $1,535,000. This estimate is based on the assumptions that manufacturers will have to change 3,000 model packages over an approximate three-year period to meet the new requirements [145] and that package label changes for each product will cost $1,335.[146] Manufacturers place information on products in the normal course of business. Annualized in the context of a 3-year PRA clearance, these non-labor costs would average $1,335,000 (3,000 model packages × $1,335 each over 3 years. As for product labeling, the Commission assumes that the one-time labeling change will cost $200 per model for an annualized estimated total of $200,000 (3,000 models × $200 over 3 years). Annualized in the context of a 3-year PRA clearance, these non-labor costs would average $1,535,000.

Estimated annual non-labor cost burden (portable air conditioners): Manufacturers are not likely to require any significant capital costs to comply with the proposed portable air conditioner amendments. Industry members, however, will incur the cost of printing labels for each covered unit. The estimated label cost, based on estimates of 1,000,000 units and $.03 per label, is $30,000 (1,000,000 × $.03).

Total Estimate: Accordingly, the revised estimated total hour burden of the proposed amendments is 54,875 with associated labor costs of $2,185,955 and annualized capital or other non-labor costs totaling $1,565,000.

Pursuant to Section 3506(c)(2)(A) of the PRA, the FTC invites comments on: (1) Whether the proposed information collection is necessary, including whether the information will be practically useful; (2) the accuracy of our burden estimates, including whether the methodology and assumptions used are valid; (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. All comments should be filed as prescribed in the **ADDRESSES** section above, and must be received on or before August 18, 2014. Comments on the proposed recordkeeping, disclosure, and reporting requirements subject to review under the PRA should additionally be submitted to OMB. If sent by U.S. mail, they should be addressed to Office of Information and Regulatory Affairs, Office of Management and Budget, Attention: Desk Officer for the Federal Trade Commission, New Executive Office Building, Docket Library, Room 10102, 725 17th Street NW., Washington, DC 20503. Comments sent to OMB by U.S. postal mail, however, are subject to delays due to heightened security precautions. Thus, comments instead should be sent by facsimile to (202) 395–5167.

V. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA), 5 U.S.C. 601–612, requires that the Commission provide an Initial Regulatory Flexibility Analysis (IRFA) with a proposed rule and a Final Regulatory Flexibility Analysis (FRFA), if any, with the final rule, unless the Commission certifies that the rule will not have a significant economic impact on a substantial number of small entities. *See* 5 U.S.C. 603–605.

The Commission does not anticipate that the proposed rule will have a significant economic impact on a substantial number of small entities. The Commission recognizes that some of the affected manufacturers may qualify as small businesses under the relevant thresholds. However, the Commission does not expect that the economic impact of the proposed amendments will be significant.

The Commission estimates that the amendments will apply to about 75 light bulb manufacturers and an additional 150 online and paper catalog sellers of covered products. The Commission expects that approximately 150 qualify as small businesses.

Accordingly, this document serves as notice to the Small Business Administration of the FTC's certification of no effect. To ensure the accuracy of this certification, however, the Commission requests comment on whether the proposed rule will have a significant impact on a substantial number of small entities, including specific information on the number of entities that would be covered by the proposed rule, the number of these companies that are small entities, and the average annual burden for each entity. Although the Commission certifies under the RFA that the rule proposed in this document would not, if promulgated, have a significant impact on a substantial number of small entities, the Commission has determined, nonetheless, that it is appropriate to publish an IRFA in order to inquire into the impact of the proposed rule on small entities. Therefore, the Commission has prepared the following analysis:

A. Description of the Reasons That Action by the Agency Is Being Taken

The Commission is proposing expanded product coverage and additional improvements to the Rule to help consumers in their purchasing decisions for high efficiency products.

B. Statement of the Objectives of, and Legal Basis for, the Proposed Rule

The objective of the rule is to improve the effectiveness of the current labeling program. The legal basis for the Rule is the Energy Policy and Conservation Act (42 U.S.C. 6292 *et seq*).

C. Small Entities to Which the Proposed Rule Will Apply

Under the Small Business Size Standards issued by the Small Business Administration, appliance manufacturers qualify as small businesses if they have fewer than 1,000 employees (for other household appliances the figure is 500 employees). Catalog sellers qualify as small businesses if their sales are less than $8.0 million annually. The Commission estimates that there are approximately 150 entities subject to the proposed rule's requirements that qualify as small

[145] This assumes that manufacturers will change packages for one third of their products in the normal course of business each year. The multi-year compliance period (two and a half years) and the notice provided by this proceeding should minimize the likelihood that manufacturers will have to discard package inventory. In addition, manufacturers may use stickers in lieu of discarding inventory.

[146] *See* 75 FR 41712 n. 149 and accompanying text.

businesses.[147] The Commission seeks comment and information with regard to the estimated number or nature of small business entities for which the proposed rule would have a significant economic impact.

D. Projected Reporting, Recordkeeping and Other Compliance Requirements

The changes under consideration would slightly increase reporting or recordkeeping requirements associated with the Commission's labeling rules as discussed above. The amendments likely will increase compliance burdens by extending the labeling requirements to new types of light bulbs and air conditioners. The Commission assumes that the label design change will be implemented by graphic designers.

E. Duplicative, Overlapping, or Conflicting Federal Rules

The Commission has not identified any other federal statutes, rules, or policies that would duplicate, overlap, or conflict with the proposed rule. The Commission invites comment and information on this issue.

F. Significant Alternatives to the Proposed Rule

The Commission seeks comment and information on the need, if any, for alternative compliance methods that, consistent with the statutory requirements, would reduce the economic impact of the rule on small entities. For example, in proposing to extend the bulb coverage, the Commission is currently unaware of the need to adopt any special provision for small entities to be able to take advantage of the proposed extension or exemption, where applicable. However, if such issues are identified, the Commission could consider alternative approaches such as extending the effective date of these amendments for catalog sellers to allow them additional time to comply beyond the labeling deadline set for manufacturers. Nonetheless, if the comments filed in response to this document identify small entities that are affected by the rule, as well as alternative methods of compliance that would reduce the economic impact of the rule on such entities, the Commission will consider the feasibility of such alternatives and determine whether they should be incorporated into the final rule.

VI. Communications by Outside Parties to the Commissioners or Their Advisors

Written communications and summaries or transcripts of oral communications respecting the merits of this proceeding, from any outside party to any Commissioner or Commissioner's advisor, will be placed on the public record. See 16 CFR 1.26(b)(5).

List of Subjects in 16 CFR Part 305

Advertising, Energy conservation, Household appliances, Labeling, Reporting and recordkeeping requirements.

For the reasons discussed above, the Commission proposes to amend part 305 of title 16, Code of Federal Regulations, as follows:

PART 305—ENERGY AND WATER USE LABELING FOR CONSUMER PRODUCTS UNDER THE ENERGY POLICY AND CONSERVATION ACT (''ENERGY LABELING RULE'')

■ 1. The authority citation for part 305 continues to read as follows:

Authority: 42 U.S.C. 6294.

■ 2. In § 305.3, revise paragraph (j) and (r), and add paragraph (z) to read as follows:

§ 305.3 Description of covered products.

* * * * *

(j) *Fluorescent lamp ballast* means a device which is used to start and operate fluorescent lamps by providing a starting voltage and current and limiting the current during normal operation.

* * * * *

(r) *Showerhead* means a component or set of components distributed in commerce for attachment to a single supply fitting, for spraying water onto a bather, typically from an overhead position, excluding safety shower showerheads.

* * * * *

(z) *Specialty consumer lamp* means:

(1) Any lamp that—

(i) Is not included under the definition of general service lamp in this part;

(ii) Has a lumen range between 310 lumens and no more than 2,600 lumens or a rated wattage between 30 and 199;

(iii) Has one of the following bases:

(A) A medium screw base;

(B) An intermediate screw base;

(C) A candelabra screw base;

(D) A GU–10 base; or

(E) A GU–24 base; and

(iv) Is capable of being operated at a voltage range at least partially within 110 and 130 volts.

(2) *Inclusions.* The term *specialty consumer lamp* includes, but is not limited to, the following lamps if such lamps meet the conditions listed in paragraph (z)(1) of this section:

(i) Vibration-service lamps as defined at 42 U.S.C. 6291(30)(AA);

(ii) Rough service lamps as defined at 42 U.S.C. 6291(30)(X);

(iii) Appliance lamps as defined at 42 U.S.C. 6291(30)(T);

(iv) Plant light lamps; and

(iv) Shatter-resistant lamps (including a shatter-proof lamp and a shatter-protected lamp) as defined in 42 U.S.C. 6291(30)(Z).

(3) *Exclusions.* The term *specialty consumer lamp* does not include:

(i) A black light lamp;

(ii) A bug lamp;

(iii) A colored lamp;

(iv) An infrared lamp;

(v) A left-hand thread lamp;

(vi) A marine lamp;

(vii) A marine signal service lamp;

(viii) A mine service lamp;

(ix) A sign service lamp;

(x) A silver bowl lamp;

(xi) A showcase lamp;

(xii) A traffic signal lamp;

(xiii) A G-shape lamp with diameter of 5 inches or more;

(xiv) A C7, M–14, P, RP, S, or T shape lamp.

■ 3. In § 305.7, revise paragraph (d) and (f) to read as follows:

§ 305.7 Determinations of Capacity

* * * * *

(d) *Water heaters.* The capacity shall be the first hour rating (for storage-type models) and gallons per minute (for instantaneous-type models), as determined according to appendix E to 10 CFR part 430, subpart B.

* * * * *

(f) *Room air conditioners.* The capacity shall be the cooling capacity in Btu's per hour, as determined according to appendix F to 10 CFR part 430, subpart B, but rounded to the nearest value ending in hundreds that will satisfy the relationship that the value of CEER used in representations equals the rounded value of capacity divided by the value of input power in watts. If a value ending in hundreds will not satisfy this relationship, the capacity may be rounded to the nearest value ending in 50 that will.

* * * * *

■ 4. In § 305.8, paragraph (a)(3) is revised to read as follows:

§ 305.8 Submission of data.

(a) * * *

(3) This section does not require reports for general service light-emitting diode (LED or OLED) lamps or specialty consumer lamps.

* * * * *

■ 5. In § 305.11, paragraphs (c), (d) introductory text, and (d)(2) are revised,

[147] *See* 75 FR 41712.

and paragraph (d)(3) is added to read as follows:

§ 305.11 Labeling for refrigerators, refrigerator-freezers, freezers, dishwashers, clothes washers, water heaters, room air conditioners, and pool heaters.

* * * * *

(c) *Colors.* Unless otherwise stated in this paragraph, the basic colors of all labels covered by this section shall be process yellow or equivalent and process black. The label shall be printed full bleed process yellow. All type and graphics shall be print process black. Room air conditioner labels printed on packaging may be printed with a color contrasting background other than yellow.

(d) *Label types.* Except as indicated in (d)(3) of this section, the labels must be affixed to the product in the form of an adhesive label or a hang tag as follows:

* * * * *

(2) *Hang Tags.* Labels may be affixed to the product in the form of a hang tag using cable ties, double strings connected through reinforced punch holes, or material with equivalent or greater strength. The paper stock for hang tags shall have a basic weight of not less than 110 pounds per 500 sheets (25 ½ ″x30 ½ ″ index). When materials are used to attach the hang tags to appliance products, the materials shall be of sufficient strength to insure that if gradual pressure is applied to the hang tag by pulling it away from where it is affixed to the product, the hang tag will tear before the material used to affix the hang tag to the product breaks.

(3) *Labels for room air conditioners.* Labels for room air conditioners shall be printed on or affixed to the principal display panel of the product's packaging.

* * * * *

■ 6. Amend § 305.12, to revise paragraph (f) to read as follows, remove paragraph (i)(4), and redesignate paragraphs (i)(5) through (i)(14) as (i)(4) through (i)(13):

§ 305.12 Labeling for central air conditioners, heat pumps, and furnaces.

* * * * *

(f) *Content of labels for furnaces.* Content of labels for non-weatherized furnaces, mobile home furnaces, electric furnaces, and boilers manufactured before the compliance date of regional efficiency standards issued by the Department of Energy in 10 CFR part 430 for non-weatherized, and mobile home furnaces and content of labels for weatherized furnaces manufactured before the compliance date of regional efficiency standards for split-system air conditioners issued by the Department of Energy in 10 CFR part 430.

(1) Headlines and texts, as illustrated in the prototype and sample labels in appendix L to this part.

(2) Name of manufacturer or private labeler shall, in the case of a corporation, be deemed to be satisfied only by the actual corporate name, which may be preceded or followed by the name of the particular division of the corporation. In the case of an individual, partnership, or association, the name under which the business is conducted shall be used. Inclusion of the name of the manufacturer or private labeler is optional at the discretion of the manufacturer or private labeler.

(3) The model's basic model number.

(4) The annual fuel utilization efficiency (AFUE) for furnace models as determined in accordance with § 305.5.

(5) Ranges of comparability consisting of the lowest and highest annual fuel utilization efficiency (AFUE) ratings for all furnaces of the model's type consistent with the sample labels in appendix L.

(6) Placement of the labeled product on the scale shall be proportionate to the lowest and highest annual fuel utilization efficiency ratings forming the scale.

(7) The following statement shall appear in bold print on furnace labels adjacent to the range(s) as illustrated in the sample labels in appendix L: For energy cost info, visit *productinfo.energy.gov.*

(8) The following statement shall appear at the top of the label as illustrated in the sample labels in appendix L: Federal law prohibits removal of this label before consumer purchase.

(9) No marks or information other than that specified in this part shall appear on or directly adjoining this label except that:

(i) A part or publication number identification may be included on this label, as desired by the manufacturer. If a manufacturer elects to use a part or publication number, it must appear in the lower right-hand corner of the label and be set in 6-point type or smaller;

(ii) The energy use disclosure labels required by the governments of Canada or Mexico may appear directly adjoining this label, as desired by the manufacturer;

(iii) The manufacturer may include the ENERGY STAR logo on the label for certified products in a location consistent with the sample labels in appendix L. The logo must be no larger than 1 inch by 3 inches in size. Only manufacturers that have signed a Memorandum of Understanding with the Department of Energy or the Environmental Protection Agency may add the ENERGY STAR logo to labels on qualifying covered products; such manufacturers may add the ENERGY STAR logo to labels only on those covered products that are contemplated by the Memorandum of Understanding.

(10) Manufacturers of boilers shipped with more than one input nozzle to be installed in the field must label such boilers with the AFUE of the system when it is set up with the nozzle that results in the lowest AFUE rating.

(11) Manufacturers that ship out boilers that may be set up as either steam or hot water units must label the boilers with the AFUE rating derived by conducting the required test on the boiler as a hot water unit.

(12) Manufacturers of oil furnaces must label their products with the AFUE rating associated with the furnace's input capacity set by the manufacturer at shipment. The oil furnace label may also contain a chart, as illustrated in sample label 9B in appendix L, indicating the efficiency rating at up to three additional input capacities offered by the manufacturer. Consistent with paragraph (f)(9)(iii) of this section, labels for oil furnaces may include the ENERGY STAR logo only if the model qualifies for that program on all input capacities displayed on the label.

* * * * *

■ 7. In § 305.13, revise paragraph (a) to read as follows:

§ 305.13 Labeling for ceiling fans.

(a) *Ceiling fans.* (1) *Content.* Any covered product that is a ceiling fan shall be labeled clearly and conspicuously on the package's principal display panel with the following information on the label consistent with the sample label in Appendix L to this part:

(i) Headlines, including the title ''EnergyGuide,'' and text as illustrated in the sample labels in Appendix L to this part;

(ii) The product's estimated yearly energy cost based on 6 hours use per day and 12 cents per kWh;

(iii) The product's airflow at high speed expressed in cubic feet per minute and determined pursuant to § 305.5 of this part;

(iv) The product's energy use at high speed expressed in watts and determined pursuant to § 305.5 of this part as indicated in the sample label in appendix L of this part;

(v) The statement ''Your cost depends on rates and use'';

(vi) The statement ''All estimates at high speed, excluding lights'';

(vii) The statement ''the higher the airflow, the more air the fan will move;''

(viii) The statement ''Airflow Efficiency: __Cubic Feet Per Minute Per Watt'''';

(ix) The address *ftc.gov/energy;*

(x) For fans fewer than 49 inches in diameter, the label shall display a cost range for 36″ to 48″ ceiling fans of $2 to $53.'';

(xi) For fans 49 inches or more in diameter, the label shall display a cost range for 49″ to 60″ ceiling fans of $3 to $29.''; and

(xii) The ENERGY STAR logo as illustrated on the ceiling fan label illustration in Appendix L for qualified products, if desired by the manufacturer. Only manufacturers that have signed a Memorandum of Understanding with the Department of Energy or the Environmental Protection Agency may add the ENERGY STAR logo to labels on qualifying covered products; such manufacturers may add the ENERGY STAR logo to labels only on those products that are covered by the Memorandum of Understanding;

(2) *Label size, color, and text font.* The label shall be four inches wide and three inches high. The label colors shall be process black text on a process yellow background. The text font shall be Arial or another equivalent font. The label's text size, format, content, and the order of the required disclosures shall be consistent with ceiling fan label illustration of appendix L of this part.

(3) *Placement.* The ceiling fan label shall be printed on or affixed to the principal display panel of the product's packaging.

(4) *Additional information.* No marks or information other than that specified in this part shall appear on this label, except a model name, number, or similar identifying information.

* * * * *

■ 8. In § 305.15, redesignate paragraphs (c), (d), (e), and (f) as paragraphs (e), (f), (g), and (h); add new paragraphs (c) and (d); and revise paragraph (b) introductory text and newly redesignated paragraphs (f)(1) and (4) to read as follows:

§ 305.15 Labeling for lighting products.

* * * * *

(b) *General service lamps.* Except as provided in paragraph (f) of this section, any covered product that is a general service lamp shall be labeled as follows:

* * * * *

(c) *Specialty consumer lamps.* (1) Any specialty consumer lamp that is a vibration-service lamp as defined at 42 U.S.C. 6291, rough service lamp as defined at 42 U.S.C. 6291(30), appliance lamp as defined at 42 U.S.C. 6291(30), plant light lamp; or shatter resistant lamp (including a shatter proof lamp and a shatter protected lamp) must be labeled pursuant to the requirements in paragraph (b).

(2) *Specialty Lighting Facts Label Content.* All specialty consumer lamps not covered by paragraph (c)(1) of this section shall be labeled either in according with paragraph (b) of this section or as follows:

(i) The principal display panel of the product package shall be labeled clearly and conspicuously with the following information consistent with the Prototype Label __ in Appendix L:

(A) The light output of each lamp included in the package, expressed as ''Brightness'' in average initial lumens rounded to the nearest five; and

(B) The estimated annual energy cost of each lamp included in the package, expressed as ''Estimated Energy Cost'' in dollars and based on usage of 3 hours per day and 11 cents ($0.11) per kWh.

(C) The life, as defined in § 305.2(w), of each lamp included in the package, expressed in years rounded to the nearest tenth (based on 3 hours operation per day);

(ii) If the lamp contains mercury, the principal display panel shall contain the following statement:

''Contains Mercury For more on clean up and safe disposal, visit *epa.gov/cfl.*''

The manufacturer may also print an ''Hg[Encircled]'' symbol on package after the term ''Contains Mercury.''

(iii) If the lamp contains mercury, the lamp shall be labeled legibly on the product with the following statement: ''Mercury disposal: *epa.gov/cfl*'' in minimum 8 point font.

(4) *Standard Lighting Facts label format.* Information specified in paragraph (c)(3) of this section shall be presented on covered lamp packages in the format, terms, explanatory text, specifications, and minimum sizes as shown in Prototype Labels __ in appendix L and consistent in format and orientation with Sample Labels in appendix L. The text and lines shall be all black or one color type, printed on a white or other neutral contrasting background whenever practical.

(i) The Lighting Facts information shall be set off in a box by use of hairlines and shall be all black or one color type, printed on a white or other neutral contrasting background whenever practical.

(ii) All information within the Lighting Facts label shall utilize:

(A) Arial or an equivalent type style;

(B) Upper and lower case letters;

(C) Leading as indicated in Prototype Label __ in appendix L;

(D) Letters that never touch;

(E) The box and hairlines separating information as illustrated in Prototype Labels __ in appendix L; and

(F) The minimum font sizes and line thicknesses as illustrated in Prototype Label __ in appendix L.

(4) *Bilingual labels.* The information required by paragraphs (c) of this section may be presented in a second language either by using separate labels for each language or in a bilingual label with the English text in the format required by this section immediately followed by the text in the second language. All required information must be included in both languages. Numeric characters that are identical in both languages need not be repeated.

(d) For lamps that do not meet the definition of general service lamp or specialty consumer lamp, manufacturers and private labelers have the discretion to label with the Lighting Facts label as long as they comply with all requirements applicable to specialty consumer lamps.

* * * * *

(f)(1) The required disclosures of any covered product that is a general service lamp or specialty consumer lamp shall be measured at 120 volts, regardless of the lamp's design voltage. If a lamp's design voltage is 125 volts or 130 volts, the disclosures of the wattage, light output, energy cost, and life ratings shall in each instance be:

* * * * *

(4) For any covered product that is a general service lamp or specialty consumer lamp and operates at discrete, multiple light levels (*e.g.,* 800, 1600, and 2500 lumens), the light output, energy cost, and wattage disclosures required by this section must be provided at each of the lamp's levels of light output and the lamp's life provided on the basis of the shortest lived operating mode. The multiple numbers shall be separated by a ''/'' (*e.g.,* 800/1600/2500 lumens) if they appear on the same line on the label.

* * * * *

■ 9. Revise paragraph (a)(1)(ii) introductory text of § 305.20 to read as follows:

§ 305.20 Paper catalogs and Web sites.

(a) * * *

(1) * * *

(ii) Products not required to bear EnergyGuide or Lighting Facts labels. All Web sites advertising covered showerheads, faucets, water closets, urinals, general service fluorescent lamps, fluorescent lamp ballasts, and metal halide lamp fixtures must include the following disclosures for each

covered product. For plumbing products, the Web site may hyperlink to the disclosures using a prominent link labeled ''Water Usage.''

* * * * *

■ 10. Revise Appendices G1, G2, G3, G4, G5, G6, G7, and G8 to read as follows:

Appendix G1 to Part 305—Furnaces—Gas

Furnace type	Range of annual fuel utilization efficiencies (AFUEs)	
	Low	High
Non-Weatherized Gas Furnaces—All Capacities	80.0	98.5
Weatherized Gas Furnaces Manufactured Before the Compliance Date of DOE Regional Standards—All Capacities	78.0	96.6
Weatherized Gas Furnaces Manufactured After the Compliance Date of DOE Regional Standards—All Capacities	____*	____*

* to be announced.

Appendix G2 to Part 305—Furnaces—Electric

Type	Range of annual fuel utilization efficiencies (AFUEs)	
	Low	High
Electric Furnaces—All Capacities	100.0	100.0

Appendix G3 to Part 305—Furnaces—Oil

Type	Range of annual fuel utilization efficiencies (AFUEs)	
	Low	High
Non-Weatherized Oil Furnaces—All Capacities	83.0	95.4
Weatherized Oil Furnaces Manufactured Before the Compliance Date of DOE Regional Standards—All Capacities	78.0	86.1
Weatherized Oil Furnaces Manufactured After the Compliance Date of DOE Regional Standards—All Capacities	____*	____*

* to be announced

Appendix G4 to Part 305—Mobile Home Furnaces—Gas

Type	Range of annual fuel utilization efficiencies (AFUEs)	
	Low	High
Mobile Home Gas Furnaces—All Capacities	80.0	96.5

Appendix G5 to Part 305—Mobile Home Furnaces—Oil

Type	Range of annual fuel utilization efficiencies (AFUEs)	
	Low	High
Mobile Home Oil Furnaces—All Capacities	75.0	86.6

Appendix G6 to Part 305—Boilers (Gas)

Type	Range of annual fuel utilization efficiencies (AFUEs)	
	Low	High
Gas Boilers—All Capacities	80.0	98.0

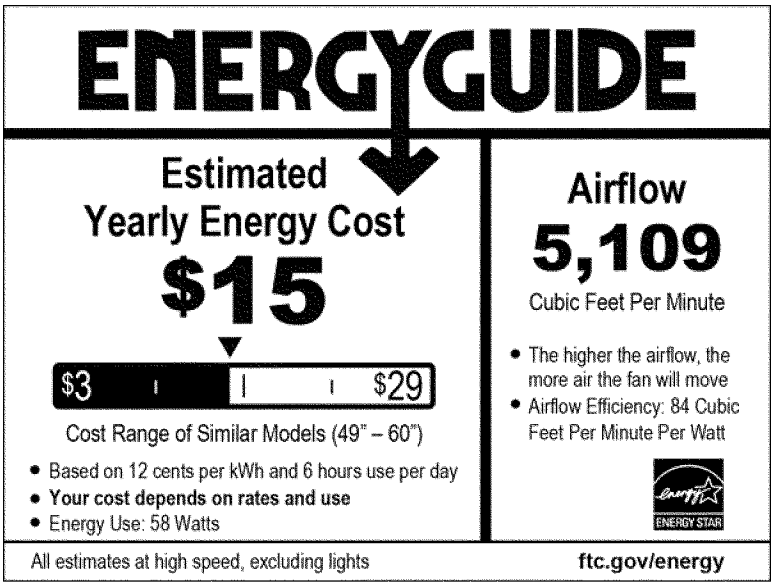
Appendix G7 to Part 305—Boilers (Oil)

Type	Range of annual fuel utilization efficiencies (AFUEs)	
	Low	High
Oil Boilers Manufactured—All Capacities	82.0	96.0

Appendix G8 to Part 305—Boilers (Electric)

Type	Range of annual fuel utilization efficiencies (AFUEs)	
	Low	High
Electric Boilers	100	100

■ 11. Amend appendix L by adding the image ''Sample Ceiling Fan Label'' to the end of the appendix to read as follows:



Sample Ceiling Fan Label

By direction of the Commission.

Donald S. Clark,

Secretary.

[FR Doc. 2014–14058 Filed 6–17–14; 8:45 am]

BILLING CODE 6750–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Chapter I

[Docket No. FDA–2013–N–0590]

RIN 0910–AG97

Implementation of the Food and Drug Administration Food Safety Modernization Act Amendments to the Reportable Food Registry Provisions of the Federal Food, Drug, and Cosmetic Act; Reopening of Comment Period

AGENCY: Food and Drug Administration, HHS.

ACTION: Advance notice of proposed rulemaking; reopening of comment period.

SUMMARY: The Food and Drug Administration (FDA or we) is reopening the comment period for the advance notice of proposed rulemaking that appeared in the **Federal Register** of March 26, 2014. In the advance notice of proposed rulemaking, FDA solicited comments, data, and information to assist the Agency in implementing the FDA Food Safety Modernization Act (FSMA), which added new provisions to the Reportable Food Registry (RFR) requirements of the Federal Food, Drug, and Cosmetic Act (the FD&C Act). We are taking this action in response to a request for an extension to allow interested persons additional time to submit comments.

DATES: Submit either electronic or written comments by August 18, 2014.

ADDRESSES: You may submit comments, identified by Agency name, Docket No. FDA–2013–N–0590 and/or Regulatory Information Number (RIN) 0910–AG97, by any of the following methods:

Electronic Submissions

Submit electronic comments in the following way:

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

Written Submissions

Submit written submissions in the following way:

• *Mail/Hand delivery/Courier (for paper submissions):* Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

Instructions: All submissions received must include the Agency name, Docket No. FDA–2013–N–0590, and RIN 0910–AG97 for this advance notice of proposed rulemaking. All comments received may be posted without change to *http://www.regulations.gov,* including any personal information provided. For additional information on submitting comments, see the ''Request for Comments'' heading of the **SUPPLEMENTARY INFORMATION** section of this document.

Docket: For access to the docket to read background documents or comments received, go to *http://www.regulations.gov* 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 Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

FOR FURTHER INFORMATION CONTACT: Ted Elkin, Center for Food Safety and Applied Nutrition (HFS–008), Food and Drug Administration, 5100 Paint Branch Pkwy, College Park, MD 20740, 240–402–2428; or April Hodges, Center for Veterinary Medicine (HFV–230), Food and Drug Administration, 7519 Standish Pl., Rockville, MD 20855, 240–276–9237.

SUPPLEMENTARY INFORMATION:

I. Background

In the **Federal Register** of March 26, 2014 (79 FR 16698), we published an advance notice of proposed rulemaking with a 75-day comment period to request comments to assist us in implementing FSMA, which added new provisions to the RFR requirements of the FD&C Act. Interested persons were originally given until June 9, 2014, to comment on the advance notice of proposed rulemaking.

We have received a request for a 60-day extension of the comment period for the advance notice of proposed rulemaking. The request conveyed concern that the 75-day comment period did not allow sufficient time to develop a meaningful or thoughtful response to the advance notice of proposed rulemaking particularly in light of other FSMA-related rulemakings for which the Agency is also requesting comments.

We have considered the request and are reopening the comment period for the advance notice of proposed rulemaking for 60 days, until August 18, 2014. We believe that reopening the comment period an additional 60 days allows adequate time for interested persons to submit comments without significantly delaying rulemaking on these important issues.

II. Request for Comments

Interested persons may submit either electronic comments regarding this document to *http://www.regulations.gov* or written comments to the Division of Dockets Management (see **ADDRESSES**). It is only necessary to send one set of comments. Received comments may be seen in the Division of Dockets Management between 9 a.m. and 4 p.m., Monday through Friday, and will be posted to the docket at *http://www.regulations.gov.*

Dated: June 13, 2014.

Leslie Kux,

Assistant Commissioner for Policy.

[FR Doc. 2014–14213 Filed 6–17–14; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 301

[REG–121542–14]

RIN 1545–BM24

Participation of a Person Described in Section 6103(n) in a Summons Interview Under Section 7602(a)(2) of the Internal Revenue Code

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice of proposed rulemaking by cross-reference to temporary regulations.

SUMMARY: In the Rules and Regulations section of this issue of the **Federal Register**, the IRS is issuing temporary regulations to modify existing regulations (TD 8091, amended by TD 9195) promulgated under section 7602(a) of the Internal Revenue Code to clarify that persons with whom the Internal Revenue Service or the Office of Chief Counsel contracts for services described in section 6103(n) and its implementing regulations may be included as persons designated to receive summoned books, papers, records, or other data and to take summoned testimony under oath. The text of the temporary regulations also serves as the text of these proposed regulations.

DATES: Written or electronic comments and requests for a public hearing must be received by September 16, 2014.

ADDRESSES: Send submissions to: CC:PA:LPD:PR (REG–121542–14), Room 5203, Internal Revenue Service, P.O. Box 7604, Ben Franklin Station, Washington, DC 20044. Submissions may be hand-delivered Monday through Friday between the hours of 8 a.m. and 4 p.m. to CC:PA:LPD:PR (REG–121542–14), Courier's Desk, Internal Revenue Service, 1111 Constitution Avenue NW., Washington, DC, or sent electronically via the Federal eRulemaking Portal at *www.regulations.gov* (IRS REG–121542–14).

FOR FURTHER INFORMATION CONTACT: Concerning submission of comments, Oluwafunmilayo (Funmi) Taylor, (202) 317–6901; concerning the proposed regulations, A M Gulas, (202) 317–6834 (not toll-free numbers).

SUPPLEMENTARY INFORMATION:

Background and Explanation of Provisions

The temporary regulations in the Rules and Regulations section of this issue of the **Federal Register** amend Procedure and Administration Regulations (26 CFR part 301) promulgated under section 7602 of the Internal Revenue Code. The text of the temporary regulations also serves as the text of these proposed regulations. The preamble to the temporary regulations explains these proposed regulations.

Special Analyses

It has been determined that this notice of proposed rulemaking is not a significant regulatory action as defined in Executive Order 12866, as supplemented by Executive Order 13563. Therefore, a regulatory assessment is not required. The IRS has also determined that section 553(b) of the Administrative Procedure Act (5 U.S.C. chapter 5) does not apply to these regulations, and because the regulations do not impose an information collection on small entities, the Regulatory Flexibility Act (5 U.S.C. chapter 6) does not apply. Therefore, a regulatory flexibility analysis is not required. Pursuant to section 7805(f) of the Internal Revenue Code, the IRS will submit the proposed regulations to the Chief Counsel for Advocacy of the Small Business Administration for comments about the regulations' impact on small business.

Comments and Requests for a Public Hearing

Before these proposed regulations are adopted as final, the IRS will consider any written (signed original and 8 copies) or electronic comments timely submitted. The IRS requests comments on all aspects of these proposed regulations. All comments will be available for public inspection and copying. The IRS will schedule a public meeting if one is requested, in writing, by a person who submits written comments. If the IRS does schedule a public hearing, the IRS will publish notice of the date, time, and place for the public hearing in the **Federal Register**.

Drafting Information

The principal author of these regulations is A M Gulas of the Office of Associate Chief Counsel (Procedure and Administration).

List of Subjects in 26 CFR Part 301

Employment taxes, estate taxes, excise taxes, gift taxes, income taxes, penalties, reporting and recordkeeping requirements.

Proposed Amendments to the Regulations

Accordingly, 26 CFR part 301 is amended as follows:

PART 301—PROCEDURE AND ADMINISTRATION

■ **Paragraph 1.** The authority citation for part 301 continues to read in part as follows:

Authority: 26 U.S.C. 7805 * * *

■ **Par. 2.** In § 301.7602–1, new paragraph (b)(3) is added to read as follows:

§ 301.7602–1 Examination of books and witnesses.

* * * * *

(b) * * *

(3) [The text of proposed § 301.7602–1(b)(3) is the same as the text of § 301.7602–1T(b)(3) published elsewhere in this issue of the **Federal Register**].

* * * * *

Heather C. Maloy,

Acting Deputy Commissioner for Services and Enforcement.

[FR Doc. 2014–14264 Filed 6–17–14; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket Number USCG–2014–0300]

RIN 1625–AA00

Safety Zones; Fireworks Displays in the Sector Columbia River Captain of the Port Zone

AGENCY: Coast Guard, DHS.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Coast Guard proposes to add twenty four new fireworks events at various locations in the Sector Columbia River Captain of the Port zone. The Coast Guard also proposes to correct the location of some existing fireworks events in the Sector Columbia River Captain of the Port zone. In addition, the Coast Guard proposes to change the format of the existing regulation by using a table to list each fireworks. When these safety zones are activated and subject to enforcement, this rule would limit the movement of vessels within the established firework display areas. These additional safety zones and corrections to existing safety zones are necessary to prevent injury and to protect life and property of the maritime public from hazards associated with fireworks displays.

DATES: Comments and related material must be received by the Coast Guard on or before July 18, 2014.

Requests for public meetings must be received by the Coast Guard on or before June 25, 2014.

ADDRESSES: You may submit comments identified by docket number USCG–2014-xxxx using any one of the following methods:

(1) *Federal eRulemaking Portal: http://www.regulations.gov*

(2) *Fax:* 202–493–2251.

(3) *Mail or Delivery:* Docket Management Facility (M–30), U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590–0001. Deliveries accepted between 9 a.m. and 5 p.m., Monday through Friday, except federal holidays. The telephone number is 202–366–9329.

See the ''Public Participation and Request for Comments'' portion of the **SUPPLEMENTARY INFORMATION** section below for further instructions on submitting comments. To avoid duplication, please use only one of these three methods.

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call or email LTJG Ian McPhillips, Waterways Management Division, Marine Safety Unit Portland, Coast Guard; telephone 503–240–9319, email *msupdxwwm@uscg.mil.* If you have questions on viewing or submitting material to the docket, call Renee V. Wright, Program Manager, Docket Operations, telephone (202) 366–9826.

SUPPLEMENTARY INFORMATION:

Table of Acronyms

DHS Department of Homeland Security
FR Federal Register
NPRM Notice of Proposed Rulemaking

A. Public Participation and Request for Comments

We encourage you to participate in this rulemaking by submitting comments and related materials. All comments received will be posted without change to *http://www.regulations.gov* and will include any personal information you have provided.

1. Submitting Comments

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. You may submit your comments and material online at *http://www.regulations.gov,* or by fax, mail, or hand delivery, but please use only one of these means. If you submit a comment online, it will be considered received by the Coast Guard when you successfully transmit the comment. If you fax, hand deliver, or mail your comment, it will be considered as having been received by the Coast Guard when it is received at the Docket Management Facility. We recommend that you include your name and a mailing address, an email address, or a telephone number in the body of your document so that we can contact you if we have questions regarding your submission.

To submit your comment online, go to *http://www.regulations.gov,* type the docket number [USCG–2014–0300] in the ''SEARCH'' box and click ''SEARCH.'' Click on ''Submit a Comment'' on the line associated with this rulemaking.

If you submit your comments by mail or hand delivery, submit them in an unbound format, no larger than 8½ by 11 inches, suitable for copying and electronic filing. If you submit comments by mail and would like to know that they reached the Facility, please enclose a stamped, self-addressed postcard or envelope. We will consider all comments and material received during the comment period and may change the rule based on your comments.

2. Viewing Comments and Documents

To view comments, as well as documents mentioned in this preamble as being available in the docket, go to *http://www.regulations.gov* type the docket number [USCG–2014–0300] in the ''SEARCH'' box and click ''SEARCH.'' Click on Open Docket Folder on the line associated with this rulemaking. You may also visit the Docket Management Facility in Room W12–140 on the ground floor of the Department of Transportation West Building, 1200 New Jersey Avenue SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

3. Privacy Act

Anyone can search the electronic form of comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review a Privacy Act notice regarding our public dockets in the January 17, 2008, issue of the **Federal Register** (73 FR 3316).

4. Public Meeting

We do not plan on holding a public meeting. But you may submit a request for one, using one of the methods specified under **ADDRESSES**. Please explain why you believe a public meeting would be beneficial. If we determine that one would aid this rulemaking, we will hold one at a time and place announced by a later notice in the **Federal Register**.

B. Basis and Purpose

The legal basis for these proposed regulations is 33 U.S.C. 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Public Law 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1 which collectively authorize the Coast Guard to establish regulatory safety zones for safety and environmental purposes.

These proposed regulations are necessary to promote the safety of life on navigable waterways during various fireworks events located within the Captain of the Port Sector Columbia River zone.

C. Discussion of Proposed Rule

Fireworks displays create hazardous conditions for the maritime public because of the large number of vessels that congregate near the displays, as well as the noise, falling debris, and explosions that occur during the event. Because fireworks discharge sites can pose a hazard to the maritime public, these proposed regulations are necessary in order to restrict vessel movement and reduce vessel congregation in the proximity of the fireworks discharge sites. The proposed corrections to the locations of some of the fireworks events listed in 33 CFR 165.1315 as well as the additional 24 safety zones proposed in this NPRM would be implemented to help ensure the safe navigation of maritime traffic in the Sector Columba River Area of Responsibility during fireworks displays.

This rule also proposes to amend the following fireworks displays into a table format and update some event positions in order to accurately reflect the coordinates of the fireworks displays listed in 33 CFR 165.1315:

Event name (typically)	Event location	Date of event	Latitude	Longitude
Cinco de Mayo Fireworks Display	Portland, OR	One day in May	45°30′55″ N	122°40′13″ W
Portland Rose Festival Fireworks Display	Portland, OR	One day in May or June.	45°30′58″ N	122°40′12″ W
Tri-City Chamber of Commerce Fireworks Display, Columbia Park.	Kennewick, WA	One day in July	46°13′47″ N	119°08′47″ W
Cedco Inc. Fireworks Display	North Bend, OR	One day in July	43°23′45″ N	124°12′50″ W
Astoria-Warrenton 4th of July Fireworks	Astoria, OR	One day in July	46°11′34″ N	123°49′28″ W
Waterfront Blues Festival Fireworks	Portland, OR	One day in July	45°30′24″ N	122°40′04″ W
Oregon Symphony Concert Fireworks Display	Portland, OR	One day in August or September.	45°30′42″ N	122°40′14″ W
Florence Independence Day Celebration	Florence, OR	One day in July	43°58′10″ N	124°05′50″ W

Event name (typically)	Event location	Date of event	Latitude	Longitude
Oaks Park Association	Portland, OR	One day in July	45°28′22″ N	122°39′59″ W
City of Rainier/Rainier Days	Rainier, OR	One day in July	46°05′46″ N	122°56′18″ W
Ilwaco July 4th Committee Fireworks/Independence Day at the Port.	Ilwaco, OR	One day in July	46°18′17″ N	124°01′55″ W
Celebrate Milwaukie	Milwaukie, OR	One day in July	45°26′33 N	122°38′44″ W
Splash Aberdeen Waterfront Festival	Aberdeen, WA	One day in July	46°58′40″ N	123°47′45″ W
City of Coos Bay July 4th Celebration/Fireworks Over the Bay.	Coos Bay, OR	One day in July	43°22′06″ N	124°12′24″ W
Arlington 4th of July	Arlington, OR	One day in July	45°43′23″ N	120°12′11 W
East County 4th of July Fireworks	Gresham, OR	One day in July	45°33′33″ N	122°27′03″ W
Port of Cascade Locks 4th of July Fireworks Display	Cascade Locks, OR	One day in July	45°40′15″ N	121°53′43″ W
Astoria Regatta	Astoria, OR	One day in August	46°11′34″ N	123°49′28″ W
Washougal 4th of July	Washougal, WA	One day in July	45°34′32″ N	122°22′53″ W
City of St. Helens 4th of July Fireworks Display	St. Helens, OR	One day in July	45°51′51″ N	122°47′22″ W
Waverly Country Club 4th of July Fireworks Display	Milwaukie, OR	One day in July	45°27′03″ N	122°39′18″ W
Booming Bay Fireworks	Westport, WA	One day in July	46°54′14″ N	124°06′08″ W
Hood River 4th of July	Hood River, OR	One day in July	45°42′58″ N	121°30′31″ W
Rufus 4th of July Fireworks	Rufus, OR	One day in July	45°41′30″ N	120°45′47″ W

This rule proposes to add twenty four new fireworks display locations, and proposes to change the title of 33 CFR 165.1315 to ''*Safety Zones; Annual Fireworks Displays within the Sector Columbia River Captain of the Port Zone.*'' 33 CFR 3.65–15.

This rule proposes to add the following fireworks displays:

Event name (typically)	Event location	Date of event	Latitude	Longitude
Newport High School Graduation Fireworks Display	Newport, OR	One day in June	44°36′48″ N	124°04′10″ W
Willamette Falls Heritage Festival	Oregon City, OR	One day in October	45°21′44″ N	122°36′21″ W
Winchester Bay 4th of July Fireworks Display	Winchester Bay, OR	One day in July	43°40′56″ N	124°11′13″ W
Brookings, OR July 4th Fireworks Display	Brookings, OR	One day in July	42°02′39″ N	124°16′14″ W
Maritime Heritage Festival	St. Helens, OR	One day in July	45°51′51″ N	122°47′22″ W
Lynch Picnic	West Linn, OR	One day in July	45°23′43″ N	122°37′58″ W
Yachats 4th of July	Yachats, OR	One day in July	44°18′38″ N	124°06′27″ W
Lincoln City 4th of July	Lincoln City, OR	One day in July	44°55′28″ N	124°01′31″ W
July 4th Party at the Port of Gold Beach	Gold Beach, OR	One day in July	42°25′26″ N	124°25′03″ W
Gardiner 4th of July	Gardiner, OR	One day in July	43°43′55″ N	124°06′48″ W
Huntington 4th of July	Huntington, OR	One day in July	44°18′02″ N	117°13′33″ W
Toledo Summer Festival	Toledo, OR	One day in July	44°37′08″ N	123°56′24″ W
Port Orford 4th of July	Port Orford, OR	One day in July	42°44′31″ N	124°29′30″ W
Hood River 4th of July	Hood River, OR	One day in July	45°42′58″ N	121°30′31″ W
The Dalles Area Chamber of Commerce Fourth of July	The Dalles, OR	One day in July	45°36′18″ N	121°10′23″ W
Roseburg Hometown 4th of July	Roseburg, OR	One day in July	43°12′59″ N	123°22′13″ W
Newport 4th of July	Newport, OR	One day in July	44°37′41″ N	124°02′54″ W
First Friday Milwaukie	Milwaukie, OR	One day in September	45°26′33″ N	122°38′44″ W
The Mill Casino Independence Day	North Bend, OR	One day in July	43°23′41″ N	124°12′49″ W
Waldport 4th of July	Waldport, OR	One day in July	44°25′31″ N	124°04′44″ W
Westport 100th Anniversary	Westport, WA	One day in June	46°54′17″ N	124°05′57″ W
Westport 4th of July	Westport, WA	One day in July	46°54′17″ N	124°05′57″ W
The 4th of July at Perkin Ferry	Ridgefield, WA	One day in July	45°52′06″ N	122°43′53″ W
Leukemia and Lymphoma Light the Night Fireworks Display	Portland, OR	One day in October	45°31′13″ N	122°40′13″ W

These safety zones will extend on and under the waters, 450 yards from the radius of the launch site described above. This zone size allows for the use of up to a 16″ mortar shell in annual fireworks displays. These zones are nominal in size and are typically positioned in areas which allow for transit around the zone. Thus, these zones have an inconsequential impact on the majority of waterway users. These zones are also short in duration and waterway users will be permitted to enter or transit through the zone when deemed safe by the on-scene patrol commander.

D. Regulatory Analyses

We developed this proposed rule after considering numerous statutes and executive orders related to rulemaking. Below we summarize our analyses based on a number of these statutes or executive orders.

1. Regulatory Planning and Review

This proposed rule is not a significant regulatory action under section 3(f) of Executive Order 12866, Regulatory Planning and Review, as supplemented by Executive Order 13563, Improving Regulation and Regulatory Review, and does not require an assessment of potential costs and benefits under section 6(a)(3) of Executive Order 12866 or under section 1 of Executive Order 13563. The Office of Management and Budget has not reviewed it under those Orders. The Coast Guard bases this finding on the fact that the safety zones listed will be in place for a limited period of time and are minimal in duration.

2. Impact on Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we have considered the impact of this proposed rule on small entities. The Coast Guard certifies under 5 U.S.C. 605(b) that this proposed rule will not have a significant economic impact on a substantial number of small entities.

(1) This rule may affect the following entities, some of which may be small entities: The owners and operators of vessels intending to operate in the area covered by the safety zone. The rule will not have a significant economic impact on a substantial number of small entities because the safety zones will only be in effect for a limited period of time. Additionally, vessels can still transit through the zone with the permission of the Captain of the Port. Before the effective period, we will publish advisories in the Local Notice to Mariners available to users of the river. Maritime traffic will be able to schedule their transits around the safety zone.

If you think that your business, organization, or governmental jurisdiction qualifies as a small entity and that this rule would have a significant economic impact on it, please submit a comment (see **ADDRESSES**) explaining why you think it qualifies and how and to what degree this rule would economically affect it.

3. Assistance for Small Entities

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

4. Collection of Information

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

5. 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 that Order and determined that this rule does not have implications for federalism.

6. Protest Activities

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

7. Unfunded Mandates Reform Act

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

8. 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.

9. 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.

10. Protection of Children From Environmental Health Risks

We have analyzed this proposed rule under Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and would not create an environmental risk to health or risk to safety that might disproportionately affect children.

11. 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.

12. Energy Effects

This proposed rule is not a ''significant energy action'' under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.

13. Technical Standards

This proposed rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

14. Environment

We have analyzed this proposed rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA)(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. This proposed rule involves the amendment to existing safety zones to reflect the correct position of the fireworks launch location and the addition of safety zones in 33 CFR 165.1315. This rule is categorically excluded from further review under paragraph 34(g) of Figure 2–1 of the Commandant Instruction. A preliminary environmental analysis checklist supporting this determination and a Categorical Exclusion Determination are available in the docket where indicated under **ADDRESSES**. 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 165

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

For the reasons discussed in the preamble, the Coast Guard proposes to amend 33 CFR Part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

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

Authority: 33 U.S.C. 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. Revise subpart § 165.1315 to read as follows:

§ 165.1315 Safety Zones; Annual Fireworks Displays within the Sector Columbia River Captain of the Port Zone.

(a) Safety Zones. The following areas are designated safety zones:

All waters of the Columbia River and its tributaries. All waters of the Siuslaw River, Yaquina River, Umpqua River as well as Washington and Oregon coasts, extending to a 450 yard radius with a 50 yard variation from the following launch sites:

Event name (typically)	Event location	Date of event	Latitude	Longitude
Cinco de Mayo Fireworks Display	Portland, OR	One day in May	45°30′55″ N	122°40′13″ W
Portland Rose Festival Fireworks Display	Portland, OR	One day in May or June.	45°30′58″ N	122°40′12″ W
Tri-City Chamber of Commerce Fireworks Display, Columbia Park.	Kennewick, WA	One day in July	46°13′47″ N	119°08′47″ W
Cedco Inc. Fireworks Display	North Bend, OR	One day in July	43°23′45″ N	124°12′50″ W
Astoria-Warrenton 4th of July Fireworks	Astoria, OR	One day in July	46°11′34″ N	123°49′28″ W
Waterfront Blues Festival Fireworks	Portland, OR	One day in July	45°30′24″ N	122°40′04″ W
Oregon Symphony Concert Fireworks Display	Portland, OR	One day in August or September.	45°30′42″ N	122°40′14″ W
Florence Independence Day Celebration	Florence, OR	One day in July	43°58′10″ N	124°05′50″ W
Oaks Park Association	Portland, OR	One day in July	45°28′22″ N	122°39′59″ W
City of Rainier/Rainier Days	Rainier, OR	One day in July	46°05′46″ N	122°56′18″ W
Ilwaco July 4th Committee Fireworks/Independence Day at the Port.	Ilwaco, OR	One day in July	46°18′17″ N	124°01′55″ W
Celebrate Milwaukie	Milwaukie, OR	One day in July	45°26′33 N	122°38′44″ W
Splash Aberdeen Waterfront Festival	Aberdeen, WA	One day in July	46°58′40″ N	123°47′45″ W
City of Coos Bay July 4th/Fireworks Over the Bay	Coos Bay, OR	One day in July	43°22′06″ N	124°12′24″ W
Arlington 4th of July	Arlington, OR	One day in July	45°43′23″ N	120°12′11 W
East County 4th of July Fireworks	Gresham, OR	One day in July	45°33′33″ N	122°27′03″ W
Port of Cascade Locks 4th of July Fireworks Display	Cascade Locks, OR	One day in July	45°40′15″ N	121°53′43″ W
Astoria Regatta	Astoria, OR	One day in August	46°11′34″ N	123°49′28″ W
Washougal 4th of July	Washougal, WA	One day in July	45°34′32″ N	122°22′53″ W
City of St. Helens 4th of July Fireworks Display	St. Helens, OR	One day in July	45°51′51″ N	122°47′22″ W
Waverly Country Club 4th of July Fireworks Display	Milwaukie, OR	One day in July	45°27′03″ N	122°39′18″ W
Booming Bay Fireworks	Westport, WA	One day in July	46°54′14″ N	124°06′08″ W
Hood River 4th of July	Hood River, OR	One day in July	45°42′58″ N	121°30′31″ W
Rufus 4th of July Fireworks	Rufus, OR	One day in July	45°41′30″ N	120°45′47″ W
Leukemia and Lymphoma Light the Night Fireworks Display.	Portland, OR	One day in October	45°31′13″ N	122°40′13″ W
Newport High School Graduation Fireworks Display	Newport, OR	One day in June	44°36′48″ N	124°04′10″ W
Willamette Falls Heritage Festival	Oregon City, OR	One day in October	45°21′44″ N	122°36′21″ W
Winchester Bay 4th of July Fireworks Display	Winchester Bay, OR	One day in July	43°40′56″ N	124°11′13″ W
Brookings, OR July 4th Fireworks Display	Brookings, OR	One day in July	42°02′39″ N	124°16′14″ W
Maritime Heritage Festival	St. Helens, OR	One day in July	45°51′51″ N	122°47′22″ W
Lynch Picnic	West Linn, OR	One day in July	45°23′43″ N	122°37′58″ W
Yachats 4th of July	Yachats, OR	One day in July	44°18′38″ N	124°06′27″ W
Lincoln City 4th of July	Lincoln City, OR	One day in July	44°55′28″ N	124°01′31″ W
July 4th Party at the Port of Gold Beach	Gold Beach, OR	One day in July	42°25′26″ N	124°25′03″ W
Gardiner 4th of July	Gardiner, OR	One day in July	43°43′55″ N	124°06′48″ W
Huntington 4th of July	Huntington, OR	One day in July	44°18′02″ N	117°13′33″ W
Toledo Summer Festival	Toledo, OR	One day in July	44°37′08″ N	123°56′24″ W
Port Orford 4th of July	Port Orford, OR	One day in July	42°44′31″ N	124°29′30″ W
Hood River 4th of July	Hood River, OR	One day in July	45°42′58″ N	121°30′31″ W
The Dalles Area Chamber of Commerce Fourth of July	The Dalles, OR	One day in July	45°36′18″ N	121°10′23″ W
Roseburg Hometown 4th of July	Roseburg, OR	One day in July	43°12′59″ N	123°22′13″ W
Newport 4th of July	Newport, OR	One day in July	44°37′41″ N	124°02′54″ W
First Friday Milwaukie	Milwaukie, OR	One day in September	45°26′33″ N	122°38′44″ W
The Mill Casino Independence Day	North Bend, OR	One day in July	43°23′41″ N	124°12′49″ W
Waldport 4th of July	Waldport, OR	One day in July	44°25′31″ N	124°04′44″ W
Westport 100th Anniversary	Westport, WA	One day in June	46°54′17″ N	124°05′57″ W
Westport 4th of July	Westport, WA	One day in July	46°54′17″ N	124°05′57″ W
The 4th of July at Perkin Ferry	Ridgefield, WA	One day in July	45°52′06″ N	122°43′53″ W

(b) Special requirements. Fireworks barges or launch sites on land used in locations stated in this rule shall display a sign. The sign will be affixed to the port and starboard side of the barge or mounted on a post 3 feet above ground level when on land and in close proximity to the shoreline facing the water labeled ''FIREWORKS—DANGER—STAY AWAY.'' This will provide on-scene notice that the safety zone is, or will, be enforced on that day. This notice will consist of a diamond shaped sign, 4 foot by 4 foot, with a 3 inch orange retro-reflective border. The word ''DANGER' shall be 10 inch black block letters centered on the sign with the words ''FIREWORKS'' and ''STAY AWAY'' in 6 inch black block letters placed above and below the word ''DANGER'' respectively on a white background. An on-scene patrol vessel may enforce these safety zones at least

1 hour prior to the start and 1 hour after the conclusion of the fireworks display.

(c) Notice of enforcement. These safety zones will be activated and thus subject to enforcement, under the following conditions: The Coast Guard must receive and approve a marine event permit for each fireworks display and then the Captain of the Port will cause notice of the enforcement of these safety zones to be made by all appropriate means to provide notice to the affected segments of the public as practicable, in accordance with 33 CFR 165.7(a). The Captain of the Port will issue a Local Notice to Mariners notifying the public of activation and suspension of enforcement of these safety zones. Additionally, an on-scene Patrol Commander may be appointed to enforce the safety zones by limiting the transit of non-participating vessels in the designated areas described above.

(d) Regulations. In accordance with the general regulations in 33 CFR part 165, subpart C, no vessel operator may enter, transit, moor, or anchor within this safety zone, except for vessels authorized by the Captain of the Port or Designated Representative.

(e) Authorization. All vessel operators who desire to enter the safety zone must obtain permission from the Captain of the Port or Designated Representative by contacting either the on-scene patrol craft on VHF Ch 13 or Ch 16 or the Coast Guard Sector Columbia River Command Center via telephone at (503) 861–6211.

(f) Enforcement period. This rule will be enforced at least 1 hour before and 1 hour after the duration of the event each day a barge or launch site with a ''FIREWORKS—DANGER—STAY AWAY'' sign is located within any of the above designated safety zone locations and meets the criteria established in paragraphs (a), (b), and (c).

(g) Contact information. Questions about safety zones and related events should be addressed to COMMANDER (spw), MARINE SAFETY UNIT PORTLAND, Attention: Waterways Management Division, 6767 N. Basin Ave, Portland, OR 97217–3992.

Dated: April 23, 2014.

B.C. Jones,

Captain, U.S. Coast Guard, Captain of the Port, Sector Columbia River.

[FR Doc. 2014–14239 Filed 6–17–14; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket Number USCG–2014–0152]

RIN 1625–AA00; 1625–AA87

Safety and Security Zones, Jacksonville Captain of the Port Zone

AGENCY: Coast Guard, DHS.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Coast Guard proposes to modify several aspects of the safety and security zones within the Sector Jacksonville Captain of the Port Zone. This action is necessary to consolidate, clarify, and otherwise modify safety and security zone regulations to eliminate unnecessary regulations and better meet the safety and security needs of the Ports of Jacksonville, Fernandina, and Canaveral. This action would modify existing safety and security zones; establish safety zones governing port closures in the event of a natural and other disasters; and remove safety and security zones.

DATES: Comments and related material must be received by the Coast Guard on or before July 9, 2014.

A public meeting will be held on June 23, 2014 at 10 a.m. at USCG Sector Jacksonville and on June 25, 2014 at 10:30 a.m. at Inter-Agency Maritime Operations Center in Cape Canaveral, FL.

ADDRESSES: You may submit comments identified by docket number using any one of the following methods:

(1) *Federal eRulemaking Portal: http://www.regulations.gov.*

(2) *Fax:* 202–493–2251.

(3) *Mail or Delivery:* Docket Management Facility (M–30), U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590–0001. Deliveries accepted between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The telephone number is (202) 366–9329. See the ''Public Participation and Request for Comments'' portion of the **SUPPLEMENTARY INFORMATION** section below for further instructions on submitting comments. To avoid duplication, please use only one of these three methods.

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call or email Commander Alisa Praskovich, Sector Jacksonville Prevention Department, Coast Guard; telephone (904) 564–7549, email *Alisa.L.Praskovich@uscg.mil.* If you have questions on viewing or submitting material to the docket, call Cheryl Collins, Program Manager, Docket Operations, telephone (202) 366–9826.

SUPPLEMENTARY INFORMATION:

Table of Acronyms

DHS Department of Homeland Security
FR Federal Register
NPRM Notice of Proposed Rulemaking

A. Public Participation and Request for Comments

We encourage you to participate in this rulemaking by submitting comments and related materials. All comments received will be posted without change to *http://www.regulations.gov* and will include any personal information you have provided.

1. Submitting Comments

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. You may submit your comments and material online at *http://www.regulations.gov*, or by fax, mail, or hand delivery, but please use only one of these means. If you submit a comment online, it will be considered received by the Coast Guard when you successfully transmit the comment. If you fax, hand deliver, or mail your comment, it will be considered as having been received by the Coast Guard when it is received at the Docket Management Facility. We recommend that you include your name and a mailing address, an email address, or a telephone number in the body of your document so that we can contact you if we have questions regarding your submission.

To submit your comment online, go to *http://www.regulations.gov*, type the docket number [USCG–2014–0152] in the ''SEARCH'' box and click ''SEARCH.'' Click on ''Submit a Comment'' on the line associated with this rulemaking.

If you submit your comments by mail or hand delivery, submit them in an unbound format, no larger than 8½ by 11 inches, suitable for copying and electronic filing. If you submit comments by mail and would like to know that they reached the Facility, please enclose a stamped, self-addressed postcard or envelope. We will consider all comments and material received during the comment period and may

change the rule based on your comments.

2. Viewing Comments and Documents

To view comments, as well as documents mentioned in this preamble as being available in the docket, go to *http://www.regulations.gov*, type the docket number (USCG–2014–0152) in the ''SEARCH'' box and click ''SEARCH.'' Click on Open Docket Folder on the line associated with this rulemaking. You may also visit the Docket Management Facility in Room W12–140 on the ground floor of the Department of Transportation West Building, 1200 New Jersey Avenue SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

3. Privacy Act

Anyone can search the electronic form of comments received into any of our dockets by the name of the individual submitting the comment (or signing the comment, if submitted on behalf of an association, business, labor union, etc.). You may review a Privacy Act notice regarding our public dockets in the January 17, 2008, issue of the **Federal Register** (73 FR 3316).

4. Public Meeting

A public meeting will be held on June 23, 2014 at 10 a.m. at USCG Sector Jacksonville and on June 25, 2014 at 10:30 a.m. at Inter-Agency Maritime Operations Center in Cape Canaveral, FL. We plan to post the minutes of the meetings in the docket. For information on facilities or services for individuals with disabilities or to request special assistance at the public meeting, contact the person named in the **FOR FURTHER INFORMATION CONTACT** section, above.

B. Regulatory History and Information

In 1994, the Coast Guard published a safety zone around firework barges between the Hart and Acosta Bridges within the Port of Jacksonville. As of 2008, there are 22 special local regulations listed under 33 CFR 100.701, which establish a 500-yard regulated area around various barges for firework display events. This regulatory change will revise the current regulations to add safety zone regulations regarding natural and other disasters port closures, as well as safety zones for all fire work displays.

C. Basis and Purpose

The legal basis for the rule is the Coast Guard's authority to establish regulated navigation areas and limited access areas: 33 U.S.C. 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, 160.5; Public Law 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

The purpose of these regulations are to ensure the safety of life on navigable waters of the United States through the addition of regulations regarding port closures in the event of natural and other disasters and safety zones for firework barges.

D. Discussion of Proposed Rule

The Coast proposes to make the following regulatory changes: (1) The disestablishment of the existing Safety/Security Zone: St. Johns River, Jacksonville, FL located in 33 CFR 165.720, (2) the creation of a new Safety Zone; Natural and Other Disasters in Ports of Jacksonville, Fernandina, and Canaveral, Florida to be located in 33 CFR 165.720, (3) and the addition of a new safety zone entitled ''Safety Zone: St. Johns River, Jacksonville, FL'' to be located in 33 CFR 165.723.

The existing Safety/Security Zone: St. Johns River, Jacksonville, FL (33 CFR 165.721) establishes safety and security zones around the waters of Blount Island, Jacksonville, FL under specified conditions. The fundamental reason for this safety/security zone still exists, however the regulation is redundant in nature. Under the authority of the Army Corps of Engineers, restricted areas were subsequently established in 2008. For further details, see Blount Island Command and Marine Corps Support Facility—Blount Island; Jacksonville, Florida restricted areas (33 CFR 334.515).

The proposed new safety zone, entitled ''Safety Zone; Natural and Other Disasters in Ports of Jacksonville, Fernandina, and Canaveral, Florida'' (33 CFR 165.720) would be added to provide the legal jurisdiction to close ports affected by natural and other disasters. In the past, temporary regulations regarding port closures have been published after natural and other disasters; however, publishing this notice in a permanent regulation provides better advance notice to the public regarding when port closures should be expected to occur, and would only require publication of a Notice of Enforcement during the storm itself, increasing efficiency and reducing the workload to the Coast Guard. There will be no change in the manner in which the public is notified by the Coast Guard of a port closure.

The proposed new safety zone, entitled ''Safety Zone: St. Johns River, Jacksonville, FL'' (33 CFR 165.723) would establish a safety zone around fireworks barges only between the Hart and Acosta Bridges. An additional regulation to encompass the Jacksonville Captain of the Port Zone will allow for a safety zone to be established around certain vessels and firework barges that pose a higher risk of injury to people or property without necessitating publication of a Temporary Final Rule for each individual event, which are often done with minimal notice to the public.

E. Regulatory Analyses

We developed this proposed rule after considering numerous statutes and executive orders related to rulemaking. Below we summarize our analyses based on a number of these statutes or executive orders.

1. Regulatory Planning and Review

This proposed rule is not a significant regulatory action under section 3(f) of Executive Order 12866, Regulatory Planning and Review, as supplemented by Executive Order 13563, Improving Regulation and Regulatory Review, and does not require an assessment of potential costs and benefits under section 6(a)(3) of Executive Order 12866 or under section 1 of Executive Order 13563. The Office of Management and Budget has not reviewed it under those Orders.

This regulation is not significant regulatory action because most of the proposed regulations already exist in some form; such as natural and other disasters safety zones as a temporary final rule for each individual natural or other disasters and special local regulations for firework displays. The regulations that are being added are not expected to have a significant regulatory action due to the infrequency of use for the safety zones around firework barges. The removal of the safety and security zone for Blount Island would have no effect as the Restricted Area set in place by the Army Corps of Engineers will remain in effect.

2. Impact on Small Entities

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

For the reasons discussed in the Regulatory Planning and Review section above, the proposed 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 rule would have a significant economic impact on it, please submit a comment (see **ADDRESSES**) explaining why you think it qualifies and how and to what degree this rule would economically affect it.

3. Assistance for Small Entities

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

4. Collection of Information

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

5. 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 that Order and determined that this rule does not have implications for federalism.

6. Protest Activities

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

7. Unfunded Mandates Reform Act

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

8. 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.

9. 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.

10. Protection of Children From Environmental Health Risks

We have analyzed this proposed rule under Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and would not create an environmental risk to health or risk to safety that might disproportionately affect children.

11. 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.

12. Energy Effects

This proposed rule is not a ''significant energy action'' under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.

13. Technical Standards

This proposed rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

14. Environment

We have analyzed this proposed rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA)(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. This proposed rule involves disestablishing of a safety and security zone, addition of port closures that would be otherwise published as a Temporary Final Rule, and addition of a safety zone to include all firework barge displays within the Jacksonville Captain of the Port Zone. This rule is categorically excluded from further review under paragraph 34(g) of Figure 2–1 of the Commandant Instruction. A preliminary environmental analysis checklist supporting this determination and a Categorical Exclusion Determination are available in the docket where indicated under **ADDRESSES**. 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 165

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

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

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

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

Authority: 33 U.S.C. 1231; 46 U.S.C. Chapter 701, 3306, 3703; 50 U.S.C. 191, 195; 33 CFR 1.05–1, 6.04–1, 6.04–6, 160.5; Pub. L. 107–295, 116 Stat. 2064; Department of Homeland Security Delegation No. 0170.1.

■ 2. Revise § 165.720 to read as follows:

§ 165.720 Safety Zone; Natural and Other Disasters in Ports of Jacksonville, Fernandina, and Canaveral, Florida.

(a) *Regulated Areas.* The following areas are established as safety zones during the specified conditions:

(1) *Fernandina, FL.* All waters within the Cumberland Sound and Amelia River encompassed within an imaginary line connecting the following locations: Starting at the demarcation line drawn across the seaward extremity of the St. Marys River Entrance Jetties; thence following the shoreline north to Stafford Island; thence north to Point 1 in position 30°50′00″ N, 81°29′10″ W;

thence west to Point 2 in position 30°50′00″ N, 81°30′47″ W; thence southwest to Kings Bay in position 30°48′42″ N, 81°3′27″ W; thence south following the shoreline south to point 3 in position 30°40′30″ N, 81°28′38″ W; thence southwest to R ''18'' at Point 4 30°39′57″ N, 81°29′04″ W; thence southeast to Point 5 30°39′48″ N, 81°28′57″ W; thence following the shoreline northeast back to origin. All coordinates are North American Datum 1983.

(2) *Jacksonville, FL.* All waters within the Port of Jacksonville, FL encompassed within following locations: Starting at the demarcation line drawn across the seaward extremity of the St. Johns River Entrance Jetties, thence following the northern riverbank west to the Sister's Creek Bridge, thence following the riverbank west to the Interstate 95 Trout River Bridge, thence following the riverbank south to the Henry H Buckman Bridge, thence following the eastern riverbank back to origin. All coordinates are North American Datum 1983.

(3) *Canaveral, FL.* All waters within the Canaveral Barge Canal in Port Canaveral, FL encompassed within the following locations: Starting at the demarcation line drawn across the seaward extremity of the Port Canaveral Entrance Channel Jetties, thence following the northern shoreline west to the SR401 Bridge, thence following the southern shoreline back to origin. All coordinates are North American Datum 1983.

(b) *Definitions.*

(1) *Designated representative.* The term ''designated representative'' means Coast Guard Patrol Commanders, including Coast Guard coxswains, petty officers, and other officers operating Coast Guard vessels, and Federal, state, and local officers designated by or assisting the Captain of the Port Jacksonville in the enforcement of the regulated area.

(2) *Hurricane Port Condition YANKEE.* Set when weather advisories indicate that sustained Gale Force winds from a tropical or hurricane force storm are predicted to make landfall at the port within 24 hours.

(3) *Hurricane Port Condition ZULU.* Set when weather advisories indicate that sustained Gale Force winds from a Tropical or hurricane force storm are predicted to make landfall at the port within 12 hours.

(c) *Regulations.*

(1) *Hurricane Port Condition YANKEE.* All commercial, oceangoing vessels and barges over 500GT are prohibited from entering in any of the 3 regulated areas designated as being in Port Condition YANKEE within the COTP Zone Jacksonville; within 24 hours of anticipated landfall of gale force winds (39 mph) from tropical or hurricane force storm; or upon the Coast Guard setting Port Condition YANKEE for inbound ocean going commercial vessel traffic over 500GT. Oceangoing commercial vessel traffic outbound will be authorized to transit through the regulated areas until Port Condition ZULU. Additionally, in the Port of Canaveral, no vessel, regardless of size or service, will be allowed to transit through the Port Canaveral Barge Canal upon the setting of Port Condition YANKEE.

(2) *Hurricane Port Condition ZULU.* All commercial, oceangoing vessels and barges over 500GT are prohibited from transiting or remaining in any of the 3 regulated areas designated as being in Port Condition ZULU within COTP Zone Jacksonville; within 12 hours of anticipated landfall of a tropical storm or hurricane; or upon the Coast Guard setting Port Condition ZULU, unless written permission is obtained from the Captain of the Port. All ship-to-shore cargo operations must cease 6 hours prior to setting Port Condition Zulu.

(3) *Emergency Closure for Other Disasters.* Any natural or other disasters that are anticipated to effect the COTP Jacksonville AOR will result in the prohibition of commercial vessel traffic transiting or remaining in any of the 3 regulated areas predicted to be effected as designated by the COTP Jacksonville.

(4) Persons and vessels desiring to enter, transit through, anchor in, or remain in the regulated area may contact the Captain of the Port Jacksonville via telephone at (904) 564–7513, or a designated representative via VHF radio on channel 16, to request authorization. If authorization to enter, transit through, anchor in, or remain in the regulated area is granted by the Captain of the Port Jacksonville or a designated representative, all persons and vessels receiving such authorization must comply with the instructions of the Captain of the Port Jacksonville or a designated representative.

(5) Coast Guard Sector Jacksonville will attempt to notify the maritime community of periods during which these safety zones will be in effect via Broadcast Notice to Mariners or by on-scene designated representatives.

■ 3. Add § 165.723 to read as follows:

§ 165.723 Safety Zone; Firework Displays in Captain of the Port Zone Jacksonville, Florida.

(a) *Regulated Area.* The following area is established as a safety zone during the specified conditions: All waters within the Jacksonville COTP Zone within a 500 yard radius of a firework barge or barges during the storage, preparation, and launching of fireworks. The Coast Guard realizes that some large scale events, such as those with many participants or spectators, or those that could severely restrict navigation or pose a significant hazard, may still require separate special local regulations or safety zones that address the specific peculiarities of the event. In those situations, the Coast Guard will create special local regulations or safety zones specifically for the event, and those regulations will supersede the proposed regulations in this rule.

(b) *Definition. Designated Representative.* The term ''designated representative'' means Coast Guard Patrol Commanders, including Coast Guard coxswains, petty officers, and other officers operating Coast Guard vessels, and Federal, state, and local officers designated by or assisting the Captain of the Port Jacksonville in the enforcement of the regulated area.

(c) *Regulations.*

(1) All persons and vessels are prohibited from entering, transiting through, anchoring in, or remaining within the regulated area unless authorized by the Coast Guard Captain of the Port Jacksonville or a designated representative.

(2) Persons and vessels desiring to enter, transit through, anchor in, or remain in the regulated area may contact the Captain of the Port Jacksonville via telephone at (904)–564–7513, or a designated representative via VHF radio on channel 16, to request authorization. If authorization to enter, transit through, anchor in, or remain in the regulated area is granted by the Captain of the Port Jacksonville or a designated representative, all persons and vessels receiving such authorization must comply with the instructions of the Captain of the Port Jacksonville or a designated representative.

(3) The Coast Guard will provide notice of the regulated area via Broadcast Notice to Mariners or by on-scene designated representatives.

(4) This regulation does not apply to authorized law enforcement agencies operating within the regulated area.

Dated: May 29, 2014.

L.A. Allen,

Commander, U.S. Coast Guard, Acting Captain of the Port Jacksonville.

[FR Doc. 2014–14176 Filed 6–17–14; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF AGRICULTURE

Forest Service

36 CFR Parts 212 and 261

RIN 0596–AD17

Use by Over-Snow Vehicles (Travel Management Rule)

AGENCY: Forest Service, USDA.

ACTION: Notice of proposed rule; request for public comment.

SUMMARY: Consistent with a court order on March 29, 2013, the U.S. Forest Service (Forest Service) is proposing to amend the agency's travel management rule (TMR) to require designation of National Forest System (NFS) roads, NFS trails, and areas on NFS lands where over-snow vehicle (OSV) use is allowed, restricted, or prohibited. Under the amended subpart C, the responsible official could establish a system of routes and areas where OSV use is prohibited except where allowed or a system of routes and areas where OSV use is allowed unless prohibited. The proposed rule would continue to exempt OSV use from subpart B of the TMR, which provides for designation of a system of routes and areas where motor vehicle use is allowed and prohibits motor vehicle use off the designated system.

DATES: Comments must be received in writing by August 4, 2014.

ADDRESSES: Submit comments electronically by following the instructions at the Federal eRulemaking portal at *http://www.regulations.gov.* Comments also may be submitted by mail to the U.S. Forest Service, Attn: Joseph Adamson, Recreation, Heritage, and Volunteer Resources Staff, 1400 Independence Avenue SW., Stop 1125, Washington, DC 20250–1125. If comments are sent electronically, please do not send duplicate comments by mail. Please confine comments to issues pertinent to the proposed rule, explain the reasons for any recommended changes, and, where possible, reference the specific section and wording being addressed. All comments, including names and addresses when provided, will be placed in the record and will be available for public inspection and copying. The public may inspect comments received on this proposed rule in the Office of the Director, Recreation, Heritage, and Volunteer Resources Staff, 5th Floor SW., 1400 Independence Avenue SW., Washington, DC, on business days between 8:30 a.m. and 4:00 p.m. Those wishing to inspect comments are encouraged to call ahead at (202) 205–0813 to facilitate entry into the building.

FOR FURTHER INFORMATION CONTACT: Joseph Adamson, (202) 205–0931, Recreation, Heritage, and Volunteer Resources Staff.

SUPPLEMENTARY INFORMATION:

Background and Need for the Rule

Between 1982 and 2009, the number of people who operated motor vehicles off road increased by more than 153 percent in the United States (''Outdoor Recreation Trends and Futures, a Technical Document Supporting the Forest Service 2010 RPA [Resources Planning Act] Assessment,'' p. 135 (H. Cordell, 2012)). While both motor vehicle use and OSV [1] use are increasing in the National Forests and Grasslands, so are many other types of recreational activities. From 1982 to 2009, the number of people in the United States participating in viewing or photographing birds increased 304.2 percent, the number of people participating in day hiking increased 228.2 percent, the number of people participating in backpacking increased 167 percent, the number of people participating in fishing increased 36 percent, and the number of people participating in hunting increased 34 percent (*id.* at 135–36). Providing for the long-term sustainable use of NFS lands and resources is essential to maintaining the quality of the recreation experience in the national forests and grasslands.

In 2005, the Forest Service promulgated the TMR to provide more effective management of public motor vehicle use. Subpart B of the TMR requires designation of those NFS roads, NFS trails, and areas on NFS lands where public motor vehicle use is allowed (36 CFR 212.51(a)). Unless exempted from the designations, public motor vehicle use is prohibited off designated routes and outside designated areas (36 CFR 261.13). Under subpart B, the responsible official must establish a system of routes and areas where motor vehicle use is allowed. This information will be displayed for the public at local district offices. Motor vehicle use off the designated system is prohibited, unless it is exempted from the designations. Subpart C of the current TMR authorizes but does not require the responsible official to allow, restrict, or prohibit OSV use on NFS roads, NFS trails, and areas on NFS lands. Under subpart C, the responsible official has the discretion to determine whether to regulate OSV use and to establish a system of routes and areas where OSV use is allowed unless prohibited or a system of routes and areas where OSV use is prohibited unless allowed. The TMR treats OSVs differently from other types of motor vehicles because an OSV traveling over snow results in different impacts on natural and cultural resource values than motor vehicles traveling over the ground. Consequently, in contrast to motor vehicles, it may be appropriate for OSVs to travel off route. 69 FR 42386, 42389 (July 15, 2004) (proposed TMR); 70 FR 68273 (Nov. 9, 2005) (final TMR).

On March 29, 2013, the United States District Court for the District of Idaho ruled that subpart C of the TMR violated Executive Order (EO) 11644, as amended by EO 11989, governing use of off-road vehicles on federal lands in giving the Forest Service discretion to determine whether to regulate OSV use, and that the agency therefore improperly denied the plaintiff's petition to amend the TMR. *Winter Wildlands Alliance* v. *USFS,* 2013 WL 1319598, No. 1:11–CV–586–REB (D. Idaho Mar. 29, 2013). The court did not rule that the Agency lacks the discretion to determine how to regulate OSV use. To the contrary, the court held that the Forest Service has the discretion to determine where and when OSV use can occur on NFS lands. This ruling requires the Agency to designate routes and areas where motor vehicle use is permitted and routes and areas where motor vehicle use is not permitted on NFS lands, consistent with EO 11644, as amended by EO 11989, sec. 3(a)), but does not dictate where and when motor vehicle use can occur on those lands. The court ordered the Forest Service to issue a new rule consistent with the EOs.

The Forest Service is proposing to amend subpart C of the TMR to provide for management of OSVs on NFS lands consistent with the EOs and the court's order. Specifically, the Forest Service is proposing to amend subpart C of the TMR to require the responsible official to designate NFS roads, NFS trails, and areas on NFS lands where OSV use is allowed, restricted, or prohibited in administrative units or Ranger Districts, or parts of administrative units or Ranger Districts, where snowfall is adequate for OSV use to occur. The Forest Service is not proposing to remove the exemption for OSVs from subpart B because the Agency wants to preserve the discretion in subpart C to establish a system of routes and areas where OSV use is allowed unless prohibited or a system of routes and areas where OSV use is prohibited unless allowed. In contrast, subpart B

[1] *See* 36 CFR 212.1 for the definition of an OSV.

requires designation of a system of routes and areas where motor vehicle use is prohibited unless allowed. Regardless of whether a unit or district establishes a system of routes and areas where OSV use is allowed unless prohibited or a system or routes and areas where OSV use is prohibited unless allowed, the decision would be based on an analysis of the impacts from the proposed designations and anticipated uses in accordance with subpart B, as modified in subpart C to provide for consistency in terminology. This information will be displayed for the public at local district offices.

The difference in management of motor vehicle use and OSV use on NFS lands stems from differences in their associated settings, activities, environmental impacts, and public preferences. National forests and grasslands change when snow blankets the landscape. Vegetation camouflages, animals burrow, and water transforms into ice. Recreationists and others accessing snow-covered National Forests and Grasslands typically trade hiking boots for skis and snowshoes and motor vehicles with tires for those with tracks and sleds.

Because of snowfall patterns, National Forests and Grasslands vary significantly in their need to address OSV use. National Visitor Use Monitoring (NVUM) data from 2008 to 2012 show that approximately 30 percent of NFS lands do not offer OSV recreation opportunities.

OSV use occurs only in the months when snow is present, in contrast to other types of motor vehicle use, which can occur at any time of the year. Other types of motor vehicles operating over snow are regulated under subpart B of the TMR.

A key difference between OSV use and other types of motor vehicle use is that, when properly operated and managed, OSVs do not make direct contact with soil, water, and vegetation, whereas most other types of motor vehicles operate directly on the ground. Unlike other types of motor vehicles traveling cross-country, OSVs traveling cross-country generally do not create a permanent trail or have a direct impact on soil and ground vegetation. In some areas of the country, OSV use is therefore not always confined to roads and trails.

The public's OSV preferences and practices on NFS lands vary nation-wide due to different terrain, snow typology and amount, recreational activities, and transportation needs. OSV use on NFS lands in the northeast and mid-west is largely trail-based, while the larger, wide-open, powder-filled bowls in western mountains support cross-country OSV use.

Subpart B of the TMR recognizes that cross-country travel by other types of motor vehicles is generally unacceptable. Subpart C of the TMR as originally promulgated and in the proposed rule recognizes that cross-country travel by OSVs may be acceptable in appropriate circumstances.

Recreational preferences are another factor accounting for the difference in management of other types of motor vehicle use and OSV use. The public's desire for recreational opportunities is different in the summer and the winter. NVUM data from 2008 to 2012 show that most public use of NFS lands (79 percent) occurs during non-snow seasons. Per NVUM data from 2008 to 2012, most snow season use on NFS lands (69 percent) occurs at alpine ski areas and generally does not involve OSVs, back-country skiing, snowshoeing, or any other snow-based activity.

Consistent with § 212.50(b) of subpart B of the current TMR, existing decisions that allow, restrict, or prohibit OSV use on NFS roads, NFS trails, or areas on NFS lands that were made under prior authorities (part 295 or subpart C) would remain in effect under the proposed rule and would not have to be revisited.

Analogous to § 212.52(a) of subpart B of the current TMR, the proposed rule would provide that public notice with no further public involvement would be sufficient if an administrative unit or a Ranger District has made previous administrative decisions, under other authorities and including public involvement, that allow, restrict, or prohibit OSV use on NFS roads, on NFS trails, and in areas on NFS lands over the entire administrative unit or Ranger District, or parts of the administrative unit or Ranger District, where snowfall is adequate for OSV use to occur and no change is proposed to these previous decisions. In short, existing OSV use determinations will remain in effect.

In requiring designation of NFS routes and areas on NFS lands where OSV use is allowed, restricted, or prohibited, the proposed rule would be consistent with the EOs and the court's order. Equally important, the resulting system of OSV routes and areas would sustain natural resource values, enhance user's experiences and provide opportunities for use on NFS lands.

Section-by-Section Analysis of the Proposed Rule

Part 212, Subpart A

Section 212.1 Definitions

Current § 212.1 of the TMR defines an area as a discrete, specifically delineated space that is smaller, and in most cases much smaller, than a Ranger District. The definition for an area in the proposed rule would recognize that cross-country OSV use may occur across a broader landscape. As with evaluation of an area for other types of motor vehicle use using the designation criteria in § 212.55, evaluation of an area for OSV use using the designation criteria in § 212.55 may be holistic and need not address each route within the area, as OSVs will be able to travel cross-country within it.

Current § 212.1 also defines ''designated road, trail, or area''. To avoid conflict with this terminology in subpart B, the proposed rule would add a definition for ''designation of over-snow vehicle use.''

Part 212, New Subpart C—Over-Snow Vehicle Use

Subpart C—Over-Snow Vehicle Use

The title of part 212, subpart C, would be changed from ''Use by Over-Snow Vehicles'' to ''Over-Snow Vehicle Use.''

Section 212.80 Purpose and Scope

Current § 212.80 states that the purpose of subpart C is to provide for regulation of OSV use on NFS roads, NFS trails, and areas on NFS lands. The proposed rule would amend this section to require designation of NFS roads, NFS trails, and areas on NFS lands where OSV use is allowed, restricted, or prohibited. Consistent with § 212.50(b) in subpart B of the current TMR, the proposed rule would include a provision authorizing the responsible official to incorporate previous administrative decisions regarding OSV use made under other authorities in allowing, restricting, or prohibiting OSV use on NFS roads, on NFS trails, and in areas on NFS lands.

Section 212.81 Over-Snow Vehicle Use

The proposed rule would amend § 212.81 to require designation of NFS roads, NFS trails, and areas on NFS lands where OSV use is allowed, restricted, or prohibited on administrative units or Ranger Districts, or parts of administrative units or Ranger Districts, of the NFS where snowfall is adequate for that use to occur, subject to the exemptions currently enumerated in § 212.81(b).

In contrast to subpart B and its corresponding prohibition at 36 CFR 261.13, which requires designation of a system of routes and areas that are open to motor vehicle use and prohibits motor vehicle use off the designated system, proposed subpart C would continue to allow the responsible official to designate a system of routes and areas where OSV use is allowed unless prohibited or a system of routes and areas where OSV use is prohibited unless allowed. An OSV use map could look like a motor vehicle use map, i.e., a map that identifies only the routes and areas where OSV use is allowed, or the opposite, i.e., a map that identifies only the routes and areas where OSV use is prohibited. In addition, local Forest Service officials would retain the discretion to manage OSV use to address local conditions and to establish restrictions, as appropriate, based on the season of use and other local factors. Decisions to designate OSV use may be made concurrently or separately from decisions to designate other types of motor vehicle use.

Consistent with § 212.52(a) of subpart B of the current TMR, § 212.81(b) of the proposed rule would provide that public notice with no further public involvement is sufficient if an administrative unit or Ranger District has made previous administrative decisions, under other authorities and including public involvement, that allow, restrict, or prohibit OSV use on NFS roads, on NFS trails, and in areas on NFS lands over the entire administrative unit or Ranger District, or parts of the administrative unit or Ranger District, where snowfall is adequate for OSV use to occur and no change is proposed to these previous decisions.

Except as modified by proposed § 212.81(b) governing prior comprehensive OSV decisions and proposed § 212.81(c) with respect to reference to the map displaying routes and areas where OSV use is allowed, restricted, or prohibited, § 212.81(c) of the proposed rule would apply the requirements governing designation of NFS roads, NFS trails, and areas on NFS lands in §§ 212.52 (public involvement); 212.53 (coordination with other governmental entities); 212.54 (revision of designations); 212.55 (criteria for designation of roads, trails, and areas); 212.56 (identification of designated roads, trails, and areas); and 212.57 (monitoring of effects of motor vehicle use) to designation of NFS roads, NFS trails, and areas on NFS lands where OSV use is allowed, restricted, or prohibited.

Part 261, Subpart A—General Prohibitions

Subpart A—General Prohibitions

The title of § 261.14 would be changed from ''Use by over-snow vehicles'' to ''Over-snow vehicle use.''

Regulatory Certifications

Regulatory Impact

This proposed rule has been reviewed under USDA procedures and EO 12866 on regulatory planning and review. The Office of Management and Budget (OMB) has determined that this proposed rule is significant and is therefore subject to OMB review under E.O. 12866.

Environmental Impact

This proposed rule would require designation at the field level, with public input, of NFS roads, NFS trails, and areas on NFS lands where OSV use is allowed, restricted, or prohibited. This proposed rule would have no effect on the ground until designation of NFS roads, NFS trails, and areas on NFS lands for OSV use is completed at the field level, with opportunity for public involvement. Forest Service regulations at 36 CFR 220.6(d)(2) exclude from documentation in an environmental assessment or environmental impact statement ''rules, regulations, or policies to establish service-wide administrative procedures, program processes, or instructions.'' The Agency has concluded that this proposed rule falls within this category of actions and that no extraordinary circumstances exist which would require preparation of an environmental assessment or environmental impact statement.

Regulatory Flexibility Act Analysis

This proposed rule has been considered in light of the Regulatory Flexibility Act (5 U.S.C. 602 *et seq.*). This proposed rule would not have any effect on small entities as defined by the Regulatory Flexibility Act. The proposed rule would require designation at the field level, with public input, of NFS roads, NFS trails, and areas on NFS lands where OSV use is allowed, restricted, or prohibited. The proposed rule would not directly affect small businesses, small organizations, and small governmental jurisdictions. The Forest Service has determined that this proposed rule would not have a significant economic impact on a substantial number of small entities pursuant to the Regulatory Flexibility Act because it would not impose recordkeeping requirements on them; it would not affect their competitive position in relation to large entities; and it would not affect their cash flow, liquidity, or ability to remain in the market.

Federalism and Consultation and Coordination With Indian Tribal Governments

The Agency has considered this proposed rule under the requirements of EO 13132 on federalism and has concluded that the proposed rule conforms with the federalism principles set out in this EO; would not impose any compliance costs on the States; and would not have substantial direct effects on the States, the relationship between the Federal Government and the States, or the distribution of power and responsibilities among the various levels of government. Therefore, the Agency has determined that no further assessment of federalism implications is necessary at this time. Moreover, this proposed rule does not have tribal implications as defined by EO 13175, entitled ''Consultation and Coordination with Indian Tribal Governments,'' and therefore advance consultation with Tribes is not required.

No Takings Implications

This proposed rule has been analyzed in accordance with the principles and criteria contained in EO 12630. The Agency has determined that the proposed rule would not pose the risk of a taking of private property.

Controlling Paperwork Burdens on the Public

This proposed rule does not contain any new recordkeeping or reporting requirements or other information collection requirements as defined in 5 U.S.C. 1320 that are not already required by law or not already approved for use. Accordingly, the review provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*) and its implementing regulations at 5 CFR part 1320 do not apply.

Energy Effects

This proposed rule has been reviewed under EO 13211, titled ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.'' The Agency has determined that this proposed rule does not constitute a significant energy action as defined in the EO.

Civil Justice Reform

This proposed rule has been reviewed under EO 12988 on civil justice reform. If the proposed rule were to be adopted, (1) all State and local laws and regulations that conflict with the proposed rule or that would impede its

full implementation would be preempted; (2) no retroactive effect would be given to the proposed rule; and (3) it would not require administrative proceedings before parties may file suit in court challenging its provisions.

Unfunded Mandates

Pursuant to Title II of the Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538), which the President signed into law on March 22, 1995, the Agency has assessed the effects of this proposed rule on State, local, and Tribal governments and the private sector. This proposed rule would not compel the expenditure of $100 million or more by any State, local, or Tribal government or anyone in the private sector. Therefore, a statement under section 202 of the act is not required.

List of Subjects

36 CFR Part 212

Highways and roads, National forests, Public lands—rights-of-way, Transportation.

36 CFR Part 261

Law enforcement, National forests.

Therefore, for the reasons set out in the preamble, the Forest Service proposes to amend 36 CFR parts 212 and 261 as follows:

PART 212—TRAVEL MANAGEMENT

Subpart A—Administration of the Forest Transportation System

■ 1. The authority citation for part 212, subpart A continues to read as follows:

Authority: 16 U.S.C. 551, 23 U.S.C. 205.

■ 2. Amend § 212.1 by revising the definition for ''Area'' and adding a definition for ''Designation of over-snow vehicle use'' in alphabetical order to read as follows:

§ 212.1 Definitions.

* * * * *

Area. A discrete, specifically delineated space that is smaller, and, except for over-snow vehicle use, in most cases much smaller, than a Ranger District.

* * * * *

Designation of over-snow vehicle use. Designation of a National Forest System road, National Forest System trail, or area on National Forest System lands where over-snow vehicle use is allowed, restricted, or prohibited pursuant to § 212.81 on an over-snow vehicle use map.

* * * * *

■ 3. Revise subpart C to read as follows:

Subpart C—Over-Snow Vehicle Use

Sec.
2.12.80 Purpose, scope, and definitions.
212.81 Over-snow vehicle use.

Authority: 7 U.S.C. 1011(f), 16 U.S.C. 551, E.O. 11644, 11989 (42 FR 26959).

§ 212.80 Purpose, scope, and definitions.

(a) *Purpose.* The purpose of this subpart is to require designation of National Forest System roads, National Forest System trails, and areas on National Forest System lands where over-snow vehicle use is allowed, restricted, or prohibited.

(b) *Scope.* The responsible official may incorporate previous administrative decisions regarding over-snow vehicle use made under other authorities in allowing, restricting, or prohibiting over-snow vehicle use on National Forest System roads, on National Forest System trails, and in areas on National Forest System lands under this subpart.

(c) *Definitions.* For definitions of terms used in this subpart, refer to § 212.1.

§ 212.81 Over-snow vehicle use.

(a) *General.* Over-snow vehicle use on National Forest System roads, on National Forest System trails, and in areas on National Forest System lands shall be designated as allowed, restricted, or prohibited by the responsible official on administrative units or Ranger Districts, or parts of administrative units or Ranger Districts, of the National Forest System where snowfall is adequate for that use to occur, provided that the following uses are exempted from these decisions:

(1) Limited administrative use by the Forest Service;

(2) Use of any fire, military, emergency, or law enforcement vehicle for emergency purposes;

(3) Authorized use of any combat or combat support vehicle for national defense purposes;

(4) Law enforcement response to violations of law, including pursuit; and

(5) Over-snow vehicle use that is specifically authorized under a written authorization issued under Federal law or regulations.

(b) *Previous comprehensive over-snow vehicle decisions.* Public notice with no further public involvement is sufficient if an administrative unit or a Ranger District has made previous administrative decisions, under other authorities and including public involvement, that allow, restrict, or prohibit over-snow vehicle use on National Forest System roads, on National Forest System trails, and in areas on National Forest System lands over the entire administrative unit or Ranger District, or parts of the administrative unit or Ranger District, where snowfall is adequate for OSV use to occur and no change is proposed to these previous decisions.

(c) *Decision-making process.* Except as modified in paragraph (b) and this paragraph, the requirements governing designation of National Forest System roads, National Forest System trails, and areas on National Forest System lands in §§ 212.52, 212.53, 212.54, 212.55, 212.56, and 212.57 shall apply to decisions made under this subpart. In making decisions under this subpart, the responsible official shall recognize the provisions concerning rights of access in sections 811(b) and 1110(a) of the Alaska National Interest Lands Conservation Act (16 U.S.C. 3121(b) and 3170(a), respectively). National Forest System roads, National Forest System trails, and areas on National Forest System lands where over-snow vehicle use is allowed, restricted, or prohibited shall be reflected on an over-snow vehicle use map.

PART 261—PROHIBITIONS

■ 4. The authority citation for part 261 continues to read as follows:

Authority: 7 U.S.C. 1011(f); 16 U.S.C. 472, 551, 620(f), 1133(c), (d)(1), 1246(i).

Subpart A—General Prohibitions

■ 5. Revise the heading of § 261.14 to read as follows:

§ 261.14 Over-snow vehicle use.

* * * * *

Dated: June 4, 2014.

Thomas L. Tidwell,

Chief, U.S. Forest Service.

[FR Doc. 2014–14273 Filed 6–17–14; 8:45 am]

BILLING CODE 3411–15–P

DEPARTMENT OF COMMERCE

United States Patent and Trademark Office

37 CFR Part 1

[Docket No.: PTO–P–2014–0023]

RIN 0651–AC96

Changes to Patent Term Adjustment in View of the Federal Circuit Decision in Novartis v. Lee

AGENCY: United States Patent and Trademark Office, Commerce.

ACTION: Notice of proposed rulemaking.

SUMMARY: The United States Patent and Trademark Office (Office) is proposing changes to the rules of practice pertaining to the patent term adjustment provisions in view of the decision by the U.S. Court of Appeals for the Federal Circuit (Federal Circuit) in *Novartis AG* v. *Lee.* The Federal Circuit confirmed in *Novartis* that any time consumed by continued examination is subtracted in determining the extent to which the period of application pendency exceeds three years, regardless when the continued examination was initiated. The Federal Circuit, however, decided that the time consumed by continued examination does not include the time after a notice of allowance, unless the Office actually resumes examination of the application after allowance. The Office is proposing changes to the rules of practice to provide that the time consumed by continued examination does not include the time after a notice of allowance, unless the Office actually resumes examination of the application after allowance. The Office also is proposing changes to the rules of practice to provide that the submission of a request for continued examination after a notice of allowance has been mailed will constitute a failure of an applicant to engage in reasonable efforts to conclude processing or examination of an application and thus result in a reduction of any period of patent term adjustment.

DATES: *Comment Deadline Date:* Written comments must be received on or before August 18, 2014.

ADDRESSES: Comments should be sent by electronic mail message over the Internet addressed to: *AC96.comments@uspto.gov.* Comments also may be submitted by postal mail addressed to: Mail Stop Comments—Patents, Commissioner for Patents, P.O. Box 1450, Alexandria, VA, 22313–1450, marked to the attention of Kery Fries, Senior Legal Advisor, Office of Patent Legal Administration, Office of the Deputy Commissioner for Patent Examination Policy.

Comments further may be sent by electronic mail message over the Internet via the Federal eRulemaking Portal. See the Federal eRulemaking Portal Web site (*http://www.regulations.gov*) for additional instructions on providing comments via the Federal eRulemaking Portal.

Although comments may be submitted by postal mail, the Office prefers to receive comments by electronic mail message over the Internet because sharing comments with the public is more easily accomplished. Electronic comments submitted in plain text are preferred, but may be submitted in ADOBE® portable document format or MICROSOFT WORD® format. Comments not submitted electronically should be submitted on paper in a format that facilitates convenient digital scanning into ADOBE® portable document format.

Comments will be available for viewing via the Office's Internet Web site (*http://www.uspto.gov*). Because comments will be made available for public inspection, information that the submitter does not desire to make public, such as an address or phone number, should not be included in the comments.

FOR FURTHER INFORMATION CONTACT: Kery Fries, Senior Legal Advisor, Office of Patent Legal Administration, Office of the Deputy Commissioner for Patent Examination Policy, at telephone number 571–272–7757.

SUPPLEMENTARY INFORMATION:

Executive Summary: Purpose: The Office is proposing changes to the rules of practice pertaining to the patent term adjustment provisions of 35 U.S.C. 154(b) in view of the decision by the Federal Circuit in *Novartis,* 740 F.3d 593 (Fed. Cir. 2014). The Federal Circuit confirmed in *Novartis* that any time consumed by continued examination under 35 U.S.C. 132(b) is subtracted in determining the extent to which the period defined in 35 U.S.C. 154(b)(1)(B) exceeds three years, regardless when the continued examination under 35 U.S.C. 132(b) was initiated. The Federal Circuit, however, decided that the time consumed by continued examination under 35 U.S.C. 132(b) does not include the time after a notice of allowance unless the Office actually resumes examination of the application after allowance.

Summary of Major Provisions: The Office is proposing changes to the rules of practice to provide that the time consumed by continued examination under 35 U.S.C. 132(b) does not include the time after a notice of allowance, unless the Office actually resumes examination of the application after allowance. The Office also is proposing changes to the rules of practice to provide that the submission of a request for continued examination under 35 U.S.C. 132(b) after a notice of allowance under 35 U.S.C. 151 has been mailed will constitute a failure of an applicant to engage in reasonable efforts to conclude processing or examination of an application and thus result in a reduction of any period of patent term adjustment under 35 U.S.C. 154(b)(1).

Costs and Benefits: This rulemaking is not economically significant under Executive Order 12866 (Sept. 30, 1993).

Background: In January 2014, the Federal Circuit issued a decision in *Novartis* pertaining to the patent term adjustment provisions of 35 U.S.C. 154(b), and specifically the impact of continued examination under 35 U.S.C. 132(b) on patent term adjustment under the three-year pendency provision of 35 U.S.C. 154(b)(1)(B). The Federal Circuit confirmed in *Novartis* that any time consumed by continued examination under 35 U.S.C. 132(b) is subtracted in determining the extent to which the period defined in 35 U.S.C. 154(b)(1)(B) exceeds three years, regardless when the continued examination under 35 U.S.C. 132(b) was initiated. *See* 740 F.3d at 601 (''[t]he better reading of the language is that the patent term adjustment time should be calculated by determining the length of the time between application and patent issuance, then subtracting any continued examination time (and other time identified in (i), (ii), and (iii) of [35 U.S.C. 154](b)(1)(B)), and determining the extent to which the result exceeds three years''). The Federal Circuit, however, decided that the time consumed by continued examination under 35 U.S.C. 132(b) does not include the time after a notice of allowance unless the Office actually resumes examination of the application after allowance. *See* 740 F.3d at 602 (''[t]he common-sense understanding of 'time consumed by continued examination,' 35 U.S.C. 154(b)(1)(B)(i), is time up to allowance, but not later, unless examination on the merits resumes''). Therefore, the Office is proposing changes to the rules of practice to provide that the time consumed by continued examination under 35 U.S.C. 132(b) does not include the time after a notice of allowance, unless the Office actually resumes examination of the application after allowance.

The Office makes the patent term adjustment determination indicated in the patent by a computer program that uses the information recorded in the Office's Patent Application Locating and Monitoring (PALM) system (except when an applicant requests reconsideration pursuant to § 1.705). *See Changes to Implement Patent Term Adjustment Under Twenty-Year Patent Term,* 65 FR 56365, 56370, 56380–81 (Sept. 18, 2000) (final rule). The decision in *Novartis* that the time consumed by continued examination under 35 U.S.C. 132(b) does not include the time after a notice of allowance unless the Office actually resumes examination of the application after

allowance requires modifications of the Office's patent term adjustment program, and these modifications of the Office's patent term adjustment program have not yet been completed. The Office, however, calculates the patent term adjustment manually when an applicant requests reconsideration of a patent term adjustment determination pursuant to § 1.705. The Office is now deciding requests for reconsideration of a patent term adjustment filed pursuant to § 1.705 consistent with the Federal Circuit decision in *Novartis.*

The patent term adjustment statutory provision also includes the provision that ''[t]he period of adjustment of the term of a patent under [35 U.S.C. 154(b)(1)] shall be reduced by a period equal to the period of time during which the applicant failed to engage in reasonable efforts to conclude prosecution of the application,'' and that ''[t]he Director shall prescribe regulations establishing the circumstances that constitute a failure of an applicant to engage in reasonable efforts to conclude processing or examination of an application.'' *See* 35 U.S.C. 154(b)(2)(C)(i) and (iii). Under the authority provided in 35 U.S.C. 154(b)(2)(C), the Office is proposing a rule of practice that establishes the submission of a request for continued examination under 35 U.S.C. 132(b) after a notice of allowance under 35 U.S.C. 151 has been mailed as constituting a failure of an applicant to engage in reasonable efforts to conclude processing or examination of an application. This rule of practice is proposed to ensure that an applicant does not obtain multiple periods of patent term adjustment under 35 U.S.C. 154(b)(1)(B) for the time after a notice of allowance under 35 U.S.C. 151 as a consequence of delaying issuance of the application by filing request for continued examination under 35 U.S.C. 132(b) after a notice of allowance under 35 U.S.C. 151.

Discussion of Specific Rules

The following is a discussion of proposed amendments to title 37 of the Code of Federal Regulations, Part 1:

Section 1.703: Section 1.703(b)(1) is proposed to be amended to provide that the time consumed by continued examination of the application under 35 U.S.C. 132(b) is the number of days, if any, in the period beginning on the date on which a request for continued examination of the application under 35 U.S.C. 132(b) was filed and ending on the date of mailing of a notice of allowance under 35 U.S.C. 151, unless prosecution in the application is reopened. If prosecution in the application is reopened, the time consumed by continued examination of the application under 35 U.S.C. 132(b) also includes the number of days, if any, in the period or periods beginning on the date on which a request for continued examination of the application under 35 U.S.C. 132(b) was filed or the date of mailing of an action under 35 U.S.C. 132, whichever occurs first, and ending on the date of mailing of a subsequent notice of allowance under 35 U.S.C. 151. As discussed previously, this proposed amendment is consistent with the decision in *Novartis* that the time consumed by continued examination under 35 U.S.C. 132(b) does not include the time after a notice of allowance unless the Office actually resumes examination of the application after allowance.

Section 1.704: Section 1.704(c) is proposed to be amended to include a new provision that establishes the submission of a request for continued examination under 35 U.S.C. 132(b) after a notice of allowance under 35 U.S.C. 151 has been mailed as constituting a failure of an applicant to engage in reasonable efforts to conclude processing or examination of an application, in which case the period of adjustment set forth in § 1.703 shall be reduced by the number of days, if any, beginning on the date of mailing of the notice of allowance under 35 U.S.C. 151 and ending on the date the request for continued examination under 35 U.S.C. 132(b) was filed. As discussed previously, this rule of practice is proposed to ensure that an applicant does not obtain multiple periods of patent term adjustment under 35 U.S.C. 154(b)(1)(B) for the time after a notice of allowance under 35 U.S.C. 151 as a consequence of delaying issuance of the application by filing request(s) for continued examination under 35 U.S.C. 132(b) after a notice of allowance under 35 U.S.C. 151. The provisions of § 1.704(d) would not be applicable to this new provision as the information disclosure statement rules (§§ 1.97 and 1.98) provide for the submission of an information disclosure statement after a notice of allowance under 35 U.S.C. 151 has been mailed up until the issue fee is paid without the need for the filing of a request for continued examination under 35 U.S.C. 132(b) (§ 1.97(d)), and the Office has a program to allow for the submission of an information disclosure statement even after the payment of the issue fee (*Quick Path Information Disclosure Statement (QPIDS) Pilot Program,* 77 FR 27443 (May 10, 2012)).

Rulemaking Considerations

A. Administrative Procedure Act: This rulemaking proposes to amend 37 CFR 1.703 to provide that the time consumed by continued examination under 35 U.S.C. 132(b) does not include the time after a notice of allowance has been mailed, unless the Office actually resumes examination of the application after allowance. This rulemaking also proposes to amend 37 CFR 1.704 to include a provision that establishes the submission of a request for continued examination under 35 U.S.C. 132(b) after a notice of allowance under 35 U.S.C. 151 has been mailed as constituting a failure of an applicant to engage in reasonable efforts to conclude processing or examination of an application. The proposed amendment to 37 CFR 1.703 to provide that the time consumed by continued examination under 35 U.S.C. 132(b) does not include the time after a notice of allowance has been mailed, unless the Office actually resumes examination of the application after allowance, simply implements the Federal Circuit's ruling on the provisions of 35 U.S.C. 154(b)(1)(B)(i) in *Novartis.* Therefore, the proposed amendment to 37 CFR 1.703 is simply a procedural and/or interpretive rule. *See Bachow Commc'ns Inc.* v. *F.C.C.,* 237 F.3d 683, 690 (D.C. Cir. 2001) (rules governing an application process are procedural under the Administrative Procedure Act); *Inova Alexandria Hosp.* v. *Shalala,* 244 F.3d 342, 350 (4th Cir. 2001) (rules for handling appeals were procedural where they did not change the substantive standard for reviewing claims); *Nat'l Org. of Veterans' Advocates, Inc.* v. *Sec'y of Veterans Affairs,* 260 F.3d 1365, 1375 (Fed. Cir. 2001) (rule that clarifies interpretation of a statute is interpretive).

Accordingly, prior notice and opportunity for public comment are not required pursuant to 5 U.S.C. 553(b) or (c) (or any other law), with respect to the proposed change to 37 CFR 1.703. *See Cooper Techs. Co.* v. *Dudas,* 536 F.3d 1330, 1336–37 (Fed. Cir. 2008) (stating that 5 U.S.C. 553, and thus 35 U.S.C. 2(b)(2)(B), does not require notice and comment rulemaking for ''interpretative rules, general statements of policy, or rules of agency organization, procedure, or practice'') (quoting 5 U.S.C. 553(b)(A)). The Office, however, is publishing all of these proposed changes (rather than only the proposed change to 37 CFR 1.704) for comment as it seeks the benefit of the public's views on the Office's proposed implementation of the Federal Circuit's interpretation of the provisions of 35 U.S.C. 154(b)(1)(B)(i) in *Novartis.*

B. Regulatory Flexibility Act: For the reasons set forth herein, the Deputy General Counsel for General Law of the United States Patent and Trademark Office has certified to the Chief Counsel for Advocacy of the Small Business Administration that changes proposed in this notice will not have a significant economic impact on a substantial number of small entities. *See* 5 U.S.C. 605(b).

The proposed changes to the patent term adjustment reduction provisions do not impose any additional requirements or fees on applicants. The proposed change to 37 CFR 1.703 simply implements the Federal Circuit's ruling on the provisions of 35 U.S.C. 154(b)(1)(B)(i) in *Novartis* and reflects how patent term adjustment is now calculated in response to a request for reconsideration of patent term adjustment. The proposed change to 37 CFR 1.704 specifies that the submission of a request for continued examination under 35 U.S.C. 132(b) after a notice of allowance under 35 U.S.C. 151 has been mailed constitutes a failure of an applicant to engage in reasonable efforts to conclude processing or examination of an application. This proposed change will not have a significant economic impact on a substantial number of small entities because applicants are not entitled to patent term adjustment for examination delays that result from an applicant's delay in prosecuting the application (35 U.S.C. 154(b)(2)(C)(i) and 37 CFR 1.704(a)) and because applicants may avoid any consequences from this provision simply by refraining from filing a request for continued examination under 35 U.S.C. 132(b) after a notice of allowance under 35 U.S.C. 151 has been mailed.

For the foregoing reasons, the changes proposed in this notice will not have a significant economic impact on a substantial number of small entities.

C. Executive Order 12866 (Regulatory Planning and Review): This rulemaking has been determined to be not significant for purposes of Executive Order 12866 (Sept. 30, 1993).

D. Executive Order 13563 (Improving Regulation and Regulatory Review): The Office has complied with Executive Order 13563. Specifically, the Office has, to the extent feasible and applicable: (1) Made a reasoned determination that the benefits justify the costs of the rule; (2) tailored the rule to impose the least burden on society consistent with obtaining the regulatory objectives; (3) selected a regulatory approach that maximizes net benefits; (4) specified performance objectives; (5) identified and assessed available alternatives; (6) involved the public in an open exchange of information and perspectives among experts in relevant disciplines, affected stakeholders in the private sector, and the public as a whole, and provided on-line access to the rulemaking docket; (7) attempted to promote coordination, simplification, and harmonization across Government agencies and identified goals designed to promote innovation; (8) considered approaches that reduce burdens and maintain flexibility and freedom of choice for the public; and (9) ensured the objectivity of scientific and technological information and processes.

E. Executive Order 13132 (Federalism): This rulemaking does not contain policies with federalism implications sufficient to warrant preparation of a Federalism Assessment under Executive Order 13132 (Aug. 4, 1999).

F. Executive Order 13175 (Tribal Consultation): This rulemaking will not: (1) Have substantial direct effects on one or more Indian tribes; (2) impose substantial direct compliance costs on Indian tribal governments; or (3) preempt tribal law. Therefore, a tribal summary impact statement is not required under Executive Order 13175 (Nov. 6, 2000).

G. Executive Order 13211 (Energy Effects): This rulemaking is not a significant energy action under Executive Order 13211 because this rulemaking is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Therefore, a Statement of Energy Effects is not required under Executive Order 13211 (May 18, 2001).

H. Executive Order 12988 (Civil Justice Reform): This rulemaking meets applicable standards to minimize litigation, eliminate ambiguity, and reduce burden as set forth in sections 3(a) and 3(b)(2) of Executive Order 12988 (Feb. 5, 1996).

I. Executive Order 13045 (Protection of Children): This rulemaking does not concern an environmental risk to health or safety that may disproportionately affect children under Executive Order 13045 (Apr. 21, 1997).

J. Executive Order 12630 (Taking of Private Property): This rulemaking will not effect a taking of private property or otherwise have taking implications under Executive Order 12630 (Mar. 15, 1988).

K. Congressional Review Act: Under the Congressional Review Act provisions of the Small Business Regulatory Enforcement Fairness Act of 1996 (5 U.S.C. 801–808), the United States Patent and Trademark Office will submit a report containing any final rule resulting from this rulemaking and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the Government Accountability Office.

L. Unfunded Mandates Reform Act of 1995: The changes set forth in this notice do not involve a Federal intergovernmental mandate that will result in the expenditure by State, local, and tribal governments, in the aggregate, of 100 million dollars (as adjusted) or more in any one year, or a Federal private sector mandate that will result in the expenditure by the private sector of 100 million dollars (as adjusted) or more in any one year, and will not significantly or uniquely affect small governments. Therefore, no actions are necessary under the provisions of the Unfunded Mandates Reform Act of 1995. *See* 2 U.S.C. 1501 *et seq.*

M. National Environmental Policy Act: This rulemaking will not have any effect on the quality of the environment and is thus categorically excluded from review under the National Environmental Policy Act of 1969. *See* 42 U.S.C. 4321 *et seq.*

N. National Technology Transfer and Advancement Act: The requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) are not applicable because this rulemaking does not contain provisions which involve the use of technical standards.

O. Paperwork Reduction Act: The Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*) requires that the Office consider the impact of paperwork and other information collection burdens imposed on the public. The rules of practice pertaining to patent term adjustment and extension have been reviewed and approved by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*) under OMB control number 0651–0020. The changes proposed in this rulemaking would: (1) Provide that the time consumed by continued examination under 35 U.S.C. 132(b) does not include the time after a notice of allowance, unless the Office actually resumes examination of the application after allowance; and (2) provide that the submission of a request for continued examination under 35 U.S.C. 132(b) after a notice of allowance under 35 U.S.C. 151 has been mailed constitutes a failure of an applicant to engage in reasonable efforts to conclude processing or examination of an application.

This rulemaking does not add any additional requirements (including information collection requirements) or

fees for patent applicants or patentees. Therefore, the Office is not resubmitting information collection packages to OMB for its review and approval because the changes in this rulemaking do not affect the information collection requirements associated with the information collections approved under OMB control number 0651–0020 or any other information collections.

Notwithstanding any other provision of 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.

List of Subjects in 37 CFR Part 1

Administrative practice and procedure, Courts, Freedom of information, Inventions and patents, Reporting and recordkeeping requirements, Small businesses.

For the reasons set forth in the preamble, 37 CFR part 1 is proposed to be amended as follows:

PART 1—RULES OF PRACTICE IN PATENT CASES

■ 1. The authority citation for 37 CFR part 1 continues to read as follows:

Authority: 35 U.S.C. 2(b)(2), unless otherwise noted.

■ 2. Section 1.703 is amended by revising paragraph (b)(1) to read as follows:

§ 1.703 Period of adjustment of patent term due to examination delay.

* * * * *

(b) * * *

(1) The number of days, if any, in the period beginning on the date on which a request for continued examination of the application under 35 U.S.C. 132(b) was filed and ending on the date of mailing of a notice of allowance under 35 U.S.C. 151, unless prosecution in the application is reopened, in which case the period of adjustment under § 1.702(b) also does not include the number of days, if any, in the period or periods beginning on the date on which a request for continued examination of the application under 35 U.S.C. 132(b) was filed or the date of mailing of an action under 35 U.S.C. 132, whichever occurs first, and ending on the date of mailing of a subsequent notice of allowance under 35 U.S.C. 151;

* * * * *

■ 2. Section 1.704 is amended by redesignating paragraphs (c)(12) and (13) as paragraphs (c)(13) and (14), respectively, and by adding a new paragraph (c)(12) to read as follows:

§ 1.704 Reduction of period of adjustment of patent term.

* * * * *

(c) * * *

(12) Submission of a request for continued examination under 35 U.S.C. 132(b) after a notice of allowance under 35 U.S.C. 151 has been mailed, in which case the period of adjustment set forth in § 1.703 shall be reduced by the number of days, if any, beginning on the date of mailing of the notice of allowance under 35 U.S.C. 151 and ending on the date the request for continued examination under 35 U.S.C. 132(b) was filed;

* * * * *

Dated: June 11, 2014.

Michelle K. Lee,

Deputy Under Secretary of Commerce for Intellectual Property and Deputy Director of the United States Patent and Trademark Office.

[FR Doc. 2014–14186 Filed 6–17–14; 8:45 am]

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DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

[Docket No. FWS–R1–ES–2013–0088; 4500030114]

RIN 1018–AZ56

Endangered and Threatened Wildlife and Plants; Designation of Critical Habitat for the Oregon Spotted Frog

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Proposed rule; reopening of comment period.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), announce the reopening of the public comment period on the August 29, 2013, proposed designation of critical habitat for the Oregon spotted frog (*Rana pretiosa*) under the Endangered Species Act of 1973, as amended (Act). We are proposing changes to four of the proposed critical habitat units based on new information we have received. We also announce the availability of a draft economic analysis (DEA) of the proposed designation of critical habitat for the Oregon spotted frog and an amended required determinations section of the proposal. We are reopening the comment period to allow all interested parties an opportunity to comment simultaneously on the proposed designation of critical habitat, the associated DEA, the amended required determinations section, and the proposed changes to the critical habitat units described in this document. Comments previously submitted need not be resubmitted, as they will be fully considered in preparation of the final rule.

DATES: The comment period for the proposed rule published August 29, 2013 (at 78 FR 53538), is reopened. We will consider comments on that proposed rule or the changes to it proposed in this document that we receive or that are postmarked on or before July 18, 2014. Comments submitted electronically using the Federal eRulemaking Portal (see **ADDRESSES** section, below) must be received by 11:59 p.m. Eastern Time on the closing date.

ADDRESSES: *Document availability:* You may obtain copies of the proposed rule and the associated draft economic analysis on the Internet at *http://www.regulations.gov* at Docket No. FWS–R1–ES–2013–0088 or by mail from the Washington Fish and Wildlife Office (see **FOR FURTHER INFORMATION CONTACT**).

Written comments: You may submit written comments by one of the following methods:

(1) *Electronically:* Go to the Federal eRulemaking Portal: *http://www.regulations.gov.* Submit comments on the critical habitat proposal and associated draft economic analysis by searching for Docket No. FWS–R1–ES–2013–0088, which is the docket number for this rulemaking.

(2) *By hard copy:* Submit comments on the critical habitat proposal and associated draft economic analysis U.S. mail or hand-delivery to: Public Comments Processing, Attn: FWS–R1–ES–2013–0088; Division of Policy and Directives Management; U.S. Fish and Wildlife Service; 4401 N. Fairfax Drive, MS 2042–PDM; Arlington, VA 22203.

We request that you send comments only by the methods described above. We will post all comments on *http://www.regulations.gov.* This generally means that we will post any personal information you provide us (see the Public Comments section below for more information).

FOR FURTHER INFORMATION CONTACT: Ken S. Berg, Manager, U.S. Fish and Wildlife Service, Washington Fish and Wildlife Office, 510 Desmond Drive SE., Suite 102, Lacey, WA 98503; telephone 360–753–9440; or facsimile 360–753–9445. Persons who use a telecommunications device for the deaf (TDD) may call the

Federal Information Relay Service (FIRS) at 800–877–8339.

SUPPLEMENTARY INFORMATION:

Public Comments

We will accept written comments and information during this reopened comment period on our proposed designation of critical habitat for the Oregon spotted frog that was published in the **Federal Register** on August 29, 2013 (78 FR 53538), our revisions to the proposed designation of critical habitat described in this document, our DEA of the proposed designation, and the amended required determinations provided in this document. We will consider information and recommendations from all interested parties. We are particularly interested in comments concerning:

(1) The reasons why we should or should not designate habitat as ''critical habitat'' under section 4 of the Act (16 U.S.C. 1531 et seq.), including whether there are threats to the species from human activity, the degree of which can be expected to increase due to the designation, and whether that increase in threats outweighs the benefit of designation such that the designation of critical habitat is not prudent.

(2) Specific information on:

(a) The amount and distribution of Oregon spotted frog habitat;

(b) What may constitute ''physical or biological features essential to the conservation of the species,'' within the geographical range currently occupied by the Oregon spotted frog;

(c) Where these features are currently found;

(d) Whether any of these features may require special management considerations or protection;

(e) What areas, that were occupied at the time of listing (or are currently occupied) and that contain features essential to the conservation of the species, should be included in the designation and why;

(f) What areas not occupied at the time of listing are essential for the conservation of the species and why;

(g) Whether there are any specific areas where the proposed critical habitat boundaries should be expanded to include adjacent riparian areas, what factors or features should be considered in determining an appropriate boundary revision, and why this would be biologically necessary or unnecessary; and

(h) Additional research studies or information regarding the movement distances or patterns of Oregon spotted frogs.

(3) Land use designations and current or planned activities in the areas proposed to be designated as critical habitat, and possible impacts of these activities on the proposed critical habitat.

(4) Information on the projected and reasonably likely impacts of climate change on the Oregon spotted frog within the proposed critical habitat areas.

(5) Any probable economic, national security, or other relevant impacts of designating any area that may be included in the final designation; in particular, we seek information on any impacts on small entities or families, and the benefits of including or excluding areas from the proposed designation that exhibit these impacts.

(6) Whether our approach to designating critical habitat could be improved or modified in any way to provide for greater public participation and understanding, or to assist us in accommodating public concerns and comments.

(7) Information on the extent to which the description of economic impacts in the draft economic analysis is a reasonable estimate of the likely economic impacts.

(8) The likelihood of adverse social reactions to the designation of critical habitat, as discussed in the associated documents of the draft economic analysis, and how the consequences of such reactions, if likely to occur, would relate to the conservation and regulatory benefits of the proposed critical habitat designation.

If you submitted comments or information on the proposed rule (78 FR 53538) during the initial comment period from August 29, 2013, to November 12, 2013, please do not resubmit them. We will incorporate them into the public record as part of this comment period, and we will fully consider them in the preparation of our final determination. Our final determination concerning critical habitat will take into consideration all written comments and any additional information we receive during both comment periods. On the basis of public comments, we may, during the development of our final determination, find that areas proposed are not essential, are appropriate for exclusion under section 4(b)(2) of the Act, or are not appropriate for exclusion.

You may submit your comments and materials concerning the proposed rule or DEA by one of the methods listed in the **ADDRESSES** section. We request that you send comments only by the methods described in the **ADDRESSES** section.

If you submit a comment via *http://www.regulations.gov,* your entire comment—including any personal identifying information—will be posted on the Web site. We will post all hardcopy comments on *http://www.regulations.gov* as well. If you submit a hardcopy comment that includes personal identifying information, you may request at the top of your document that we withhold this information from public review. However, we cannot guarantee that we will be able to do so.

Comments and materials we receive, as well as supporting documentation we used in preparing the proposed rule and DEA, will be available for public inspection on *http://www.regulations.gov* at Docket No. FWS–R1–ES–2013–0088, or by appointment, during normal business hours, at the U.S. Fish and Wildlife Service, Washington Fish and Wildlife Office (see **FOR FURTHER INFORMATION CONTACT**). You may obtain copies of the proposed rule and the DEA on the Internet at *http://www.regulations.gov* at Docket Number FWS–R1–ES–2013–0088, or by mail from the Washington Fish and Wildlife Office (see **FOR FURTHER INFORMATION CONTACT**).

Background

It is our intent to discuss only those topics directly relevant to the designation of critical habitat for Oregon spotted frog in this document. For more information on previous Federal actions concerning the Oregon spotted frog, refer to the proposed designation of critical habitat published in the **Federal Register** on August 29, 2013 (78 FR 53538). For more information on the Oregon spotted frog or its habitat, refer to the proposed listing rule published in the **Federal Register** on August 29, 2013 (78 FR 53582), which is available online at *http://www.regulations.gov* (at Docket Number FWS–R1–ES–2013–0013) or from the Washington Fish and Wildlife Office (see **FOR FURTHER INFORMATION CONTACT**).

On August 29, 2013, we published a proposed rule to list the Oregon spotted frog as a threatened species (78 FR 53582) and a proposed rule to designate critical habitat for the Oregon spotted frog (78 FR 53538). We proposed to designate approximately 68,192 acres (27,597 hectares (ha)) and approximately 24 river miles (mi) (38 river kilometers (km)) in 14 units located in Washington and Oregon as critical habitat. That proposal had a 60-day comment period, to end October 28, 2013. On September 26, 2013, we extended the public comment period an additional 15 days, until November 12, 2013, to allow all interested parties additional time to comment on the

proposed rules, and we announced that we would hold a public hearing (78 FR 59334). The public hearing was held on October 21, 2013, in Lacey, Washington. We will submit for publication in the **Federal Register** a final critical habitat designation for the Oregon spotted frog after we receive public comment on the changes to the proposed critical habitat described in this document, the DEA, and the amended required determinations provided in this document.

Critical Habitat

Section 3 of the Act defines critical habitat as the specific areas within the geographical area occupied by a species, at the time it is listed in accordance with the Act, on which are found those physical or biological features essential to the conservation of the species and that may require special management considerations or protection, and specific areas outside the geographical area occupied by a species at the time it is listed, upon a determination that such areas are essential for the conservation of the species. If the proposed rule is made final, section 7 of the Act will prohibit destruction or adverse modification of critical habitat by any activity funded, authorized, or carried out by any Federal agency. Federal agencies proposing actions affecting critical habitat must consult with us on the effects of their proposed actions under section 7(a)(2) of the Act.

Changes From Previously Proposed Critical Habitat

The Service received new information from Federal partners and the public that led to our refinement of four of the proposed critical habitat units in Oregon. We are proposing to expand the four units to include a total of 309 additional acres (125 additional ha). All of the additional areas are known to be occupied by Oregon spotted frogs and are subject to the same suite of activities described in our August 29, 2013, proposed designation (78 FR 53538). The approximate acreages to be added to the four units, as well as the landownership, are shown below in Table 1. There are no changes being proposed in the other 10 proposed critical habitat units.

TABLE 1—APPROXIMATE AREA AND LANDOWNERSHIP OF CHANGES TO PROPOSED CRITICAL HABITAT UNITS FOR THE OREGON SPOTTED FROG. ALL UNITS IN TABLE ARE LOCATED IN OREGON

Critical habitat unit	Additional federal ac (ha)	Additional state ac (ha)	Additional county ac (ha)	Additional private/ local municipalities ac (ha)	Total additional proposed ac (ha)	Total Proposed ac (ha)
7. Lower Deschutes River	27 (11)	0	0	0	27 (11)	96 (39)
12. Williamson River	82 (33)	0	0	98 (40)	180 (73)	15,332 (6,205)
13. Upper Klamath Lake	7 (3)	3 (1)	0	75 (30)	85 (34)	2,336 (946)
14. Upper Klamath	15 (6)	0	0	2 (1)	17 (7)	262 (106)
Total	131 (53)	3 (1)	0	175 (71)	309 (125)	

Note: Area sizes may not sum due to rounding. Area estimates reflect all land and river miles within proposed critical habitat unit boundaries.

Changes to Proposed Critical Habitat Units

Critical Habitat Unit 7: Lower Deschutes River

A comment we received from a peer reviewer indicated that the proposed critical habitat unit did not include overwintering habitat currently used by Oregon spotted frogs at Camas Prairie (Corkran 2013). Upon consideration of the information we received, we propose to include an additional 27 acres (11 ha) of the meadow and springs that provide overwintering habitat for the Oregon spotted frog. The additional acreage is occupied by the Oregon spotted frog, contains the physical or biological features essential to the conservation of the species, and occurs entirely on the Mt. Hood National Forest. The essential features within the additional acres may require special management considerations or protection to ensure maintenance or improvement of existing overwintering habitat, aquatic movement corridors, or refugia habitat, and to address any changes that could affect these features. The total acreage of proposed critical habitat in Unit 7, after this refinement, is 96 acres (39 ha) in Wasco County, Oregon.

Critical Habitat Unit 12: Williamson River

New information we received from the U.S. Geological Survey indicated that the proposed critical habitat unit did not include the full extent of occupancy by Oregon spotted frogs along Jack Creek (C. Pearl, USGS, pers. comm. 2014). Therefore, we propose to include an additional 180 acres (73 ha) in this unit. Upon consideration of the information we received, this refinement includes approximately 3.1 miles (5 km) of Jack Creek and its adjacent seasonally wetted areas south of U.S. Forest Service Road 88 through 1.32 mi (2.12 km) of O'Connor Meadow. The additional acreage is occupied by the Oregon spotted frog and contains the physical or biological features essential to the conservation of the species. Eighty-two acres (33 ha) are managed by the Fremont-Winema National Forest, and 98 acres (40 ha) are privately owned. The essential features within the additional acres may require special management considerations or protection to ensure maintenance or improvement of the existing nonbreeding, breeding, rearing, and overwintering habitat; aquatic movement corridors; or refugia habitat, and to address any changes that could affect these features. The total acreage of proposed critical habitat in Unit 12, after this refinement, is 15,332 acres (6,205 ha) in Klamath County, Oregon.

Critical Habitat Unit 13: Upper Klamath Lake

New information we received from the U.S. Geological Survey and National Park Service indicated that the proposed critical habitat unit did not include the full extent of occupancy by Oregon spotted frogs (D. Hering, NPS, pers. comm. 2014; C. Pearl, pers. comm. 2013). Upon consideration of the information we received, we propose to include an additional 85 acres (34 ha) in this unit. This refinement includes approximately 0.75 mi (1.2 km) of Annie Creek and the associated, adjacent, seasonally wetted areas from the Annie Creek Sno-Park downstream to its junction with the Wood River;

approximately 1.19 mi (1.92 km) of Sun Creek and the associated, adjacent, seasonally wetted areas from the boundary of State and private property to the junction with Annie Creek; and approximately 1.10 mi (1.77 km) of Blue Spring and the associated, adjacent, seasonally wetted areas from the spring origin to the junction of Short Creek. The additional acreage is occupied by the Oregon spotted frog and contains the physical or biological features essential to the conservation of the species. Seven acres (3 ha) are managed by the Bureau of Land Management and Fremont-Winema National Forest, 3 acres (1 ha) are managed by Oregon State Parks, and 75 acres (30 ha) are privately owned. The essential features within the additional acres may require special management considerations or protection to ensure maintenance or improvement of the existing nonbreeding, breeding, rearing, and overwintering habitat; aquatic movement corridors; or refugia habitat, and to address any changes that could affect these features. The total acreage of proposed critical habitat in Unit 13, after this refinement, is 2,336 acres (946 ha) in Klamath County, Oregon.

Critical Habitat Unit 14: Upper Klamath

New information we received from the U.S. Forest Service indicated the proposed critical habitat unit did not include the full extent of occupancy by Oregon spotted frogs (T. Smith, USFS, pers. comm. 2014). Therefore, we propose to include an additional 17 acres (7 ha) in this unit. Upon consideration of the information we received, this refinement includes an additional portion of the Buck Lake drainage system of canals, as well as Spencer Creek from Buck Lake downstream approximately 1.6 miles (2.6 km), ending at the intersection of U.S. Forest Service Road 46 and Clover Creek Road. The additional acreage is occupied by the Oregon spotted frog and contains the essential physical or biological features. Fifteen acres (6 ha) are managed by the Bureau of Land Management and Fremont-Winema National Forest, and 2 acres (1 ha) are privately owned. The essential features within the additional acres may require special management considerations or protection to ensure maintenance or improvement of the existing nonbreeding, breeding, rearing, and overwintering habitat; aquatic movement corridors; or refugia habitat, and to address any changes that could affect these features. The total acreage of proposed critical habitat in Unit 14, after this refinement, is 262 acres (106 ha) in Klamath and Jackson Counties, Oregon.

Consideration of Impacts Under Section 4(b)(2) of the Act

Section 4(b)(2) of the Act requires that we designate or revise critical habitat based upon the best scientific data available, after taking into consideration the economic impact, impact on national security, or any other relevant impact of specifying any particular area as critical habitat. We may exclude an area from critical habitat if we determine that the benefits of excluding the area outweigh the benefits of including the area as critical habitat, provided such exclusion will not result in the extinction of the species.

When considering the benefits of inclusion for an area, we consider among other factors, the additional regulatory benefits that an area would receive through the analysis under section 7 of the Act addressing the destruction or adverse modification of critical habitat as a result of actions with a Federal nexus (activities conducted, funded, permitted, or authorized by Federal agencies), the educational benefits of identifying areas containing essential features that aid in the recovery of the listed species, and any ancillary benefits triggered by existing local, State or Federal laws as a result of the critical habitat designation.

When considering the benefits of exclusion, we consider, among other things, whether exclusion of a specific area is likely to incentivize or result in conservation; the continuation, strengthening, or encouragement of partnerships; or implementation of a management plan. In the case of the Oregon spotted frog, the benefits of critical habitat include public awareness of the presence of the Oregon spotted frog and the importance of habitat protection, and, where a Federal nexus exists, increased habitat protection for the Oregon spotted frog due to protection from adverse modification or destruction of critical habitat. In practice, situations with a Federal nexus exist primarily on Federal lands or for projects undertaken by Federal agencies.

The final decision on whether to exclude any areas will be based on the best scientific data available at the time of the final designation, including information obtained during the comment period and information about the economic impact of designation. Accordingly, we have prepared a draft economic analysis concerning the proposed critical habitat designation (DEA), which is available for review and comment (see **ADDRESSES**).

Consideration of Economic Impacts

Section 4(b)(2) of the Act and its implementing regulations require that we consider the economic impact that may result from a designation of critical habitat. To assess the probable economic impacts of a designation, we must first evaluate specific land uses or activities and projects that may occur in the area of the critical habitat. We then must evaluate the impacts that a specific critical habitat designation may have on restricting or modifying specific land uses or activities for the benefit of the species and its habitat within the areas proposed. We then identify which conservation efforts may be the result of the species being listed under the Act versus those attributed solely to the designation of critical habitat for this particular species. The probable economic impact of a proposed critical habitat designation is analyzed by comparing scenarios ''with critical habitat'' and ''without critical habitat.'' The ''without critical habitat'' scenario represents the baseline for the analysis, which includes the existing regulatory and socio-economic burden imposed on landowners, managers, or other resource users potentially affected by the designation of critical habitat (e.g., under the Federal listing as well as other Federal, State, and local regulations). The baseline, therefore, represents the costs of all efforts attributable to the listing of the species under the Act (i.e., conservation of the species and its habitat incurred regardless of whether critical habitat is designated). The ''with critical habitat'' scenario describes the incremental impacts associated specifically with the designation of critical habitat for the species. The incremental conservation efforts and associated impacts would not be expected without the designation of critical habitat for the species. In other words, the incremental costs are those attributable solely to the designation of critical habitat, above and beyond the baseline costs. These are the costs we use when evaluating the benefits of inclusion and exclusion of particular areas from the final designation of critical habitat should we choose to conduct an optional section 4(b)(2) exclusion analysis.

For this particular designation, we developed an incremental effects memorandum (IEM) considering the probable incremental economic impacts that may result from this proposed designation of critical habitat. The information contained in our IEM was then used to develop a screening analysis of the probable effects of the designation of critical habitat for the

Oregon spotted frog (IEc, April 30, 2014). We began by conducting a screening analysis of the proposed designation of critical habitat in order to focus our analysis on the key factors that are likely to result in incremental economic impacts. The purpose of the screening analysis is to filter out the geographic areas in which the critical habitat designation is unlikely to result in probable incremental economic impacts. In particular, the screening analysis considers baseline costs (i.e., absent critical habitat designation) and includes probable economic impacts where land and water use may be subject to conservation plans, land management plans, best management practices, or regulations that protect the habitat area as a result of the Federal listing status of the species. The screening analysis filters out particular areas of critical habitat that are already subject to such protections and are, therefore, unlikely to incur incremental economic impacts. The screening analysis also assesses whether units are unoccupied by the species and may require additional management or conservation efforts as a result of the critical habitat designation and may incur incremental economic impacts. This screening analysis, combined with the information contained in our IEM, is what we consider our draft economic analysis of the proposed critical habitat designation for the Oregon spotted frog and is summarized in the narrative below.

Executive Orders (E.O.) 12866 and 13563 direct Federal agencies to assess the costs and benefits of available regulatory alternatives in quantitative (to the extent feasible) and qualitative terms. Consistent with the E.O. regulatory analysis requirements, our effects analysis under the Act may take into consideration impacts to both directly and indirectly impacted entities, where practicable and reasonable. We assess, to the extent practicable, the probable impacts, if sufficient data are available, to both directly and indirectly impacted entities. As part of our screening analysis, we considered the types of economic activities that are likely to occur within the areas likely affected by the critical habitat designation. In our evaluation of the probable incremental economic impacts that may result from the proposed designation of critical habitat for the Oregon spotted frog, first we identified, in the IEM dated January 14, 2014, and the IEM addendum dated February 13, 2014, probable incremental economic impacts associated with the following categories of activities: (1) Grazing, (2) water management, (3) land restoration and conservation, (4) agriculture, (5) recreation, and (6) transportation activities. We considered each industry or category individually. Additionally, we considered whether their activities have any Federal involvement. Critical habitat designation will not affect activities that do not have any Federal involvement; designation of critical habitat only affects activities conducted, funded, permitted, or authorized by Federal agencies. If the listing proposal is made final, in areas where the Oregon spotted frog is present, Federal agencies would be required to consult with the Service under section 7 of the Act on activities they fund, permit, or implement that may affect the species. If we also finalize the proposed critical habitat designation, consultations to avoid the destruction or adverse modification of critical habitat would be incorporated into the existing consultation process. Therefore, disproportionate impacts to any geographic area or sector are not likely as a result of this critical habitat designation.

In our IEM, we attempted to clarify the distinction between the effects that would result from the species being listed and those attributable to the critical habitat designation (i.e., difference between the jeopardy and adverse modification standards) for the Oregon spotted frog's critical habitat. Because the designation of critical habitat for Oregon spotted frog was proposed concurrently with the listing, it has been our experience that it is more difficult to discern which conservation efforts are attributable to the species being listed and those which will result solely from the designation of critical habitat. However, the following specific circumstances in this case help to inform our evaluation: (1) The essential physical or biological features identified for critical habitat are the same features essential for the life history requisites of the species, and (2) any actions that would result in sufficient harm or harassment to constitute jeopardy to the Oregon spotted frog would also likely adversely affect the essential physical and biological features of critical habitat. The IEM outlines our rationale concerning this limited distinction between baseline conservation efforts and incremental impacts of the designation of critical habitat for this species. This evaluation of the incremental effects has been used as the basis to evaluate the probable incremental economic impacts of the proposed designation of critical habitat.

The proposed critical habitat designation for the Oregon spotted frog totals approximately 68,500 acres (27,721 ha) and 24 river mi (38 river km). The majority of these areas are occupied by the Oregon spotted frog, although approximately 365 acres (148 ha) and less than 1 river mile are not known to be occupied by the species. In occupied areas, any actions that may affect the species or its habitat would also affect designated critical habitat, and it is unlikely that any additional conservation efforts would be recommended to address the adverse modification standard over and above those recommended as necessary to avoid jeopardizing the continued existence of the Oregon spotted frog. Additionally, in areas proposed as critical habitat that are not known to be occupied by the Oregon spotted frog, Federal action agencies are likely to treat these areas as potentially occupied due to their proximity to occupied areas, and any project modifications requested to avoid adverse modification are likely to be the same as those needed to avoid jeopardy. Therefore, only administrative costs are expected due to the proposed critical habitat designation. While this additional analysis will require time and resources by both the Federal action agency and the Service, it is believed that, in most circumstances, these costs would predominantly be administrative in nature and would not be significant. The unit likely to incur the largest incremental administrative costs is Unit 9 (Little Deschutes River) due to a relatively high number of anticipated consultations to consider grazing allotments intersecting the unit. The total incremental administrative costs associated with all known future actions are estimated to be $190,000. Thus, future probable incremental economic impacts are not likely to exceed $100 million in any single year and disproportionate impacts to any geographic area or sector are not likely as a result of this critical habitat designation.

Therefore, the probable incremental economic impacts of the Oregon spotted frog critical habitat designation are expected to be limited to additional administrative effort in conducting future section 7 consultations. This is due to three factors: (1) In occupied areas, activities with a Federal nexus would be subject to section 7 consultation requirements regardless of critical habitat designation, due to the presence of the listed species; (2) In areas not known to be occupied, agencies would in most cases be likely

to treat areas as potentially occupied due to their proximity to occupied areas; and (3) project modifications requested to avoid adverse modification would be likely to be the same as those needed to avoid jeopardy.

As we stated earlier, we are soliciting data and comments from the public on the DEA, as well as all aspects of the proposed rule and our amended required determinations. We may revise the proposed rule or supporting documents to incorporate or address information we receive during the public comment period. In particular, we may exclude an area from critical habitat if we determine that the benefits of excluding the area outweigh the benefits of including the area, provided the exclusion will not result in the extinction of this species.

Required Determinations—Amended

In our August 29, 2013, proposed rule (78 FR 53538), we determined our compliance with several statutes and executive orders. Following our evaluation of the probable incremental economic impacts resulting from the designation of critical habitat for the Oregon spotted frog, we have amended or affirmed our determinations below. Specifically, we affirm the information in our proposed rule concerning Executive Orders (E.O.s) 12866 and 13563 (Regulatory Planning and Review), E.O. 13132 (Federalism), E.O. 12988 (Civil Justice Reform), E.O. 13211 (Energy, Supply, Distribution, or Use), the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*), the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*), and the President's memorandum of April 29, 1994, ''Government-to-Government Relations with Native American Tribal Governments'' (59 FR 22951). However, based on our evaluation of the probable incremental economic impacts of the proposed designation of critical habitat for the Oregon spotted frog, we are amending our required determinations concerning the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) and E.O. 12630 (Takings).

Regulatory Flexibility Act (5 U.S.C. 601 et seq.)

Under the Regulatory Flexibility Act (RFA; 5 U.S.C. 601 *et seq.*), as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA; 5 U.S.C. 801 *et seq.*), whenever an agency is required to publish a notice of rulemaking for any proposed or final rule, it must prepare and make available for public comment a regulatory flexibility analysis that describes the effects of the rule on small entities (i.e., small businesses, small organizations, and small government jurisdictions). However, no regulatory flexibility analysis is required if the head of the agency certifies the rule will not have a significant economic impact on a substantial number of small entities. The SBREFA amended the RFA to require Federal agencies to provide a certification statement of the factual basis for certifying that the rule will not have a significant economic impact on a substantial number of small entities.

According to the Small Business Administration, small entities include small organizations such as independent nonprofit organizations; small governmental jurisdictions, including school boards and city and town governments that serve fewer than 50,000 residents; and small businesses (13 CFR 121.201). Small businesses include manufacturing and mining concerns with fewer than 500 employees, wholesale trade entities with fewer than 100 employees, retail and service businesses with less than $5 million in annual sales, general and heavy construction businesses with less than $27.5 million in annual business, special trade contractors doing less than $11.5 million in annual business, and agricultural businesses with annual sales less than $750,000. To determine if potential economic impacts to these small entities are significant, we considered the types of activities that might trigger regulatory impacts under this designation as well as types of project modifications that may result. In general, the term ''significant economic impact'' is meant to apply to a typical small business firm's business operations.

The Service's current understanding of the requirements under the RFA, as amended, and following recent court decisions, is that Federal agencies are only required to evaluate the potential incremental impacts of rulemaking on those entities directly regulated by the rulemaking itself, and therefore, not required to evaluate the potential impacts to indirectly regulated entities. The regulatory mechanism through which critical habitat protections are realized is section 7 of the Act, which requires Federal agencies, in consultation with the Service, to ensure that any action authorized, funded, or carried out by the agency is not likely to adversely modify critical habitat. Therefore, under these circumstances only Federal action agencies are directly subject to the specific regulatory requirement (avoiding destruction and adverse modification) imposed by critical habitat designation. Under these circumstances, it is our position that only Federal action agencies will be directly regulated by this designation. Federal agencies are not small entities and to this end, there is no requirement under RFA to evaluate the potential impacts to entities not directly regulated. Therefore, because no small entities are directly regulated by this rulemaking, the Service certifies that, if promulgated, the proposed critical habitat designation will not have a significant economic impact on a substantial number of small entities.

In summary, we have considered whether the proposed designation would result in a significant economic impact on a substantial number of small entities. For the above reasons and based on currently available information, we certify that, if promulgated, the proposed critical habitat designation would not have a significant economic impact on a substantial number of small business entities. Therefore, an initial regulatory flexibility analysis is not required.

E.O. 12630 (Takings)

In accordance with E.O. 12630 (Government Actions and Interference with Constitutionally Protected Private Property Rights), we have analyzed the potential takings implications of designating critical habitat for the Oregon spotted frog in a takings implications assessment. As discussed above, the designation of critical habitat affects only Federal actions. Although private parties that receive Federal funding, assistance, or require approval or authorization from a Federal agency for an action may be indirectly impacted by the designation of critical habitat, the legally binding duty to avoid destruction or adverse modification of critical habitat rests squarely on the Federal agency. The economic analysis found that no significant economic impacts are likely to result from the designation of critical habitat for the Oregon spotted frog. Because the Act's critical habitat protection requirements apply only to Federal agency actions, few conflicts between critical habitat and private property rights should result from this designation. Based on information contained in the economic analysis assessment and described within this document, it is not likely that economic impacts to a property owner would be of a sufficient magnitude to support a takings action. Therefore, the takings implications assessment concludes that this designation of critical habitat for Oregon spotted frog does not pose significant takings implications for lands within or affected by the designation.

Authors

The primary authors of this notice are the staff members of the Washington Fish and Wildlife Office, Oregon Fish and Wildlife Office-Bend Field Office, and Klamath Falls Fish and Wildlife Office.

List of Subjects in 50 CFR Part 17

Endangered and threatened species, Exports, Imports, Reporting and recordkeeping requirements, Transportation.

Proposed Regulation Promulgation

Accordingly, we propose to further amend part 17, subchapter B of chapter I, title 50 of the Code of Federal Regulations, as proposed to be amended on August 29, 2013, at 78 FR 53538, as set forth below:

PART 17—[AMENDED]

■ 1. The authority citation for part 17 continues to read as follows:

Authority: 16 U.S.C. 1361–1407; 1531–1544; 4201–4245, unless otherwise noted.

■ 2. Amend § 17.95(d) by revising paragraphs (12), (18), (19), and (20) in the entry proposed for ''Oregon Spotted Frog (*Rana pretiosa*)'' at 78 FR 53538 to read as follows:

§ 17.95 Critical habitat—fish and wildlife.

* * * * *

(d) *Amphibians.*

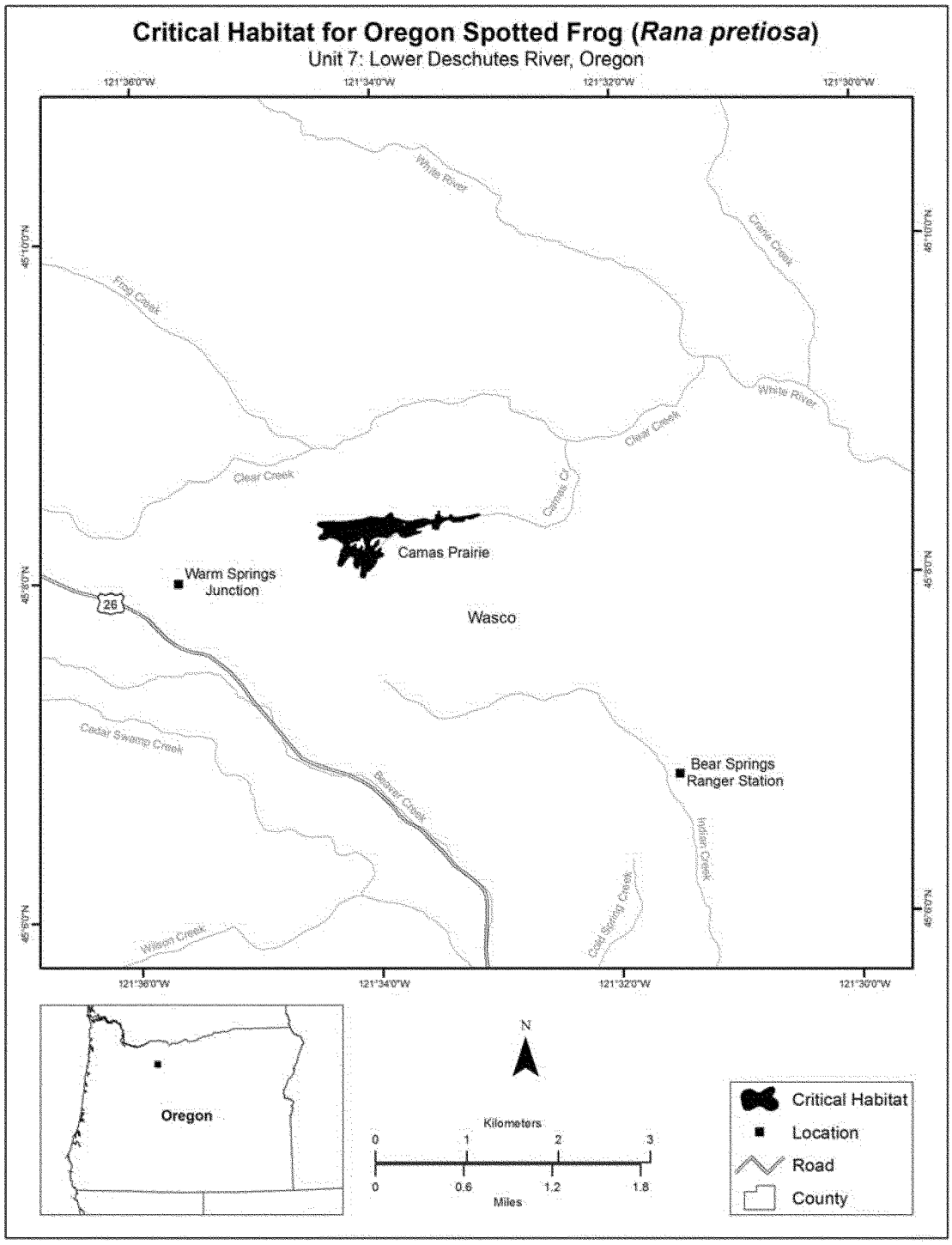
* * * * *

Oregon Spotted Frog (*Rana pretiosa*)

* * * * *

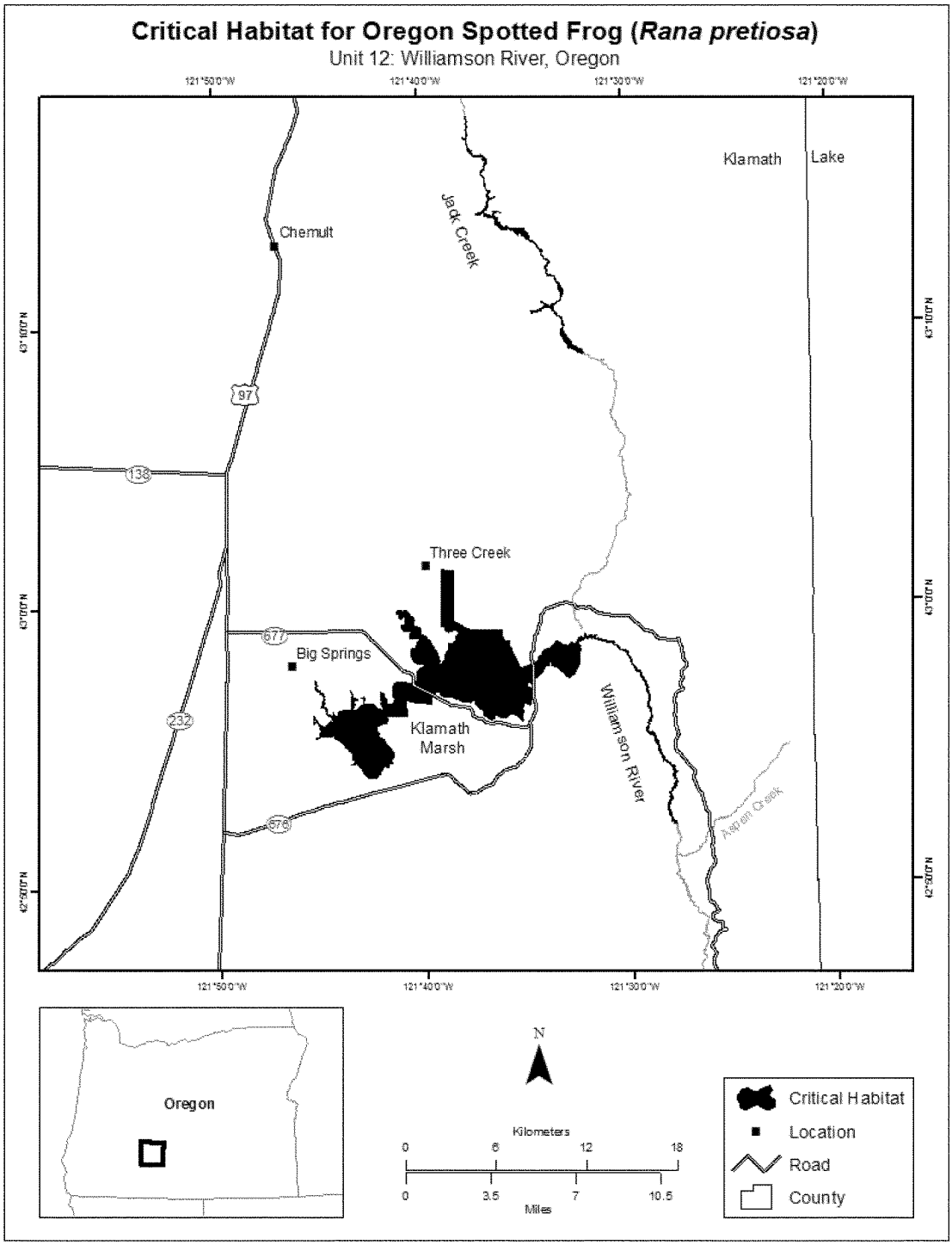
(12) Unit 7: Lower Deschutes River, Wasco County, Oregon. Map of Unit 7 follows:

BILLING CODE 4310–55–P

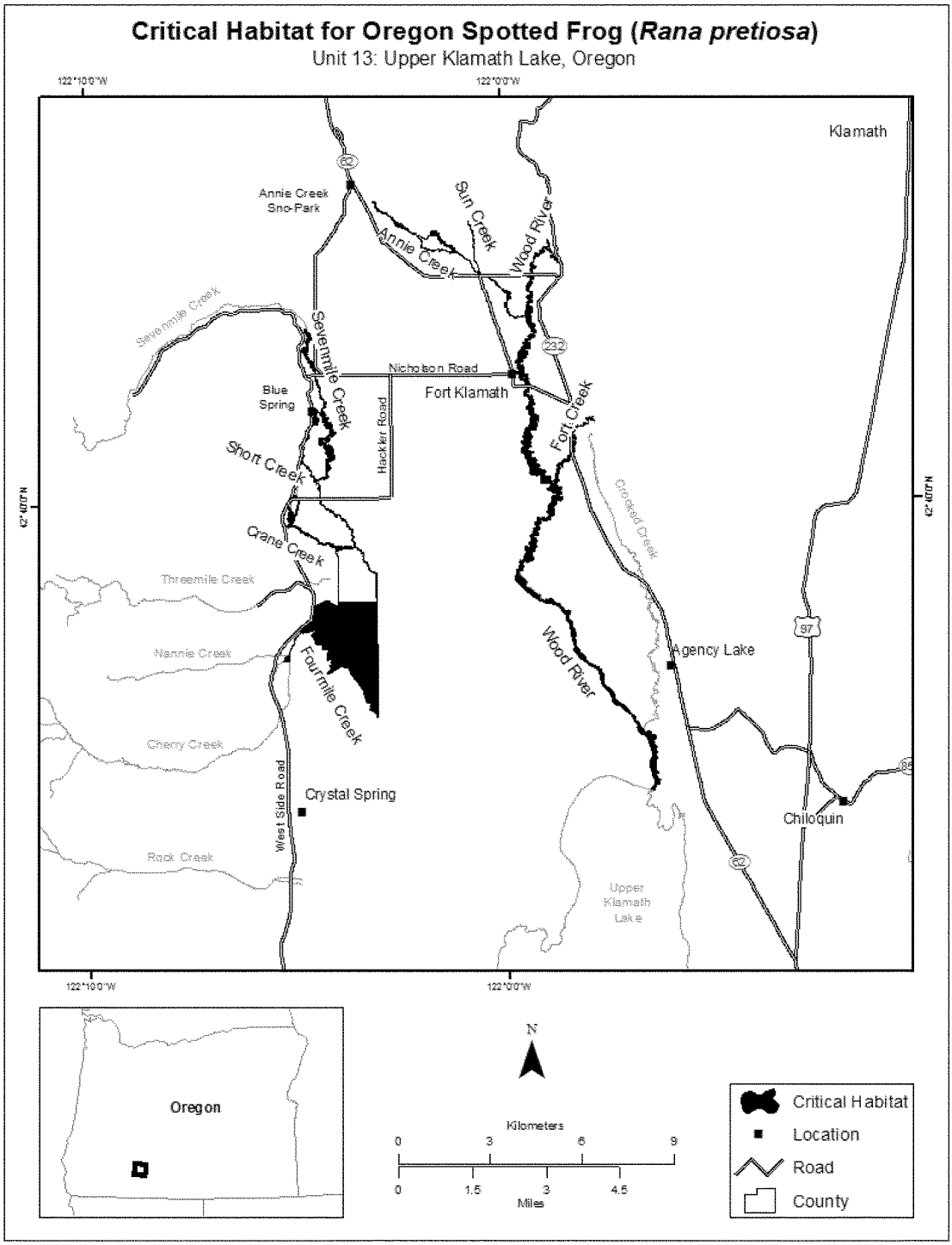


* * * * *

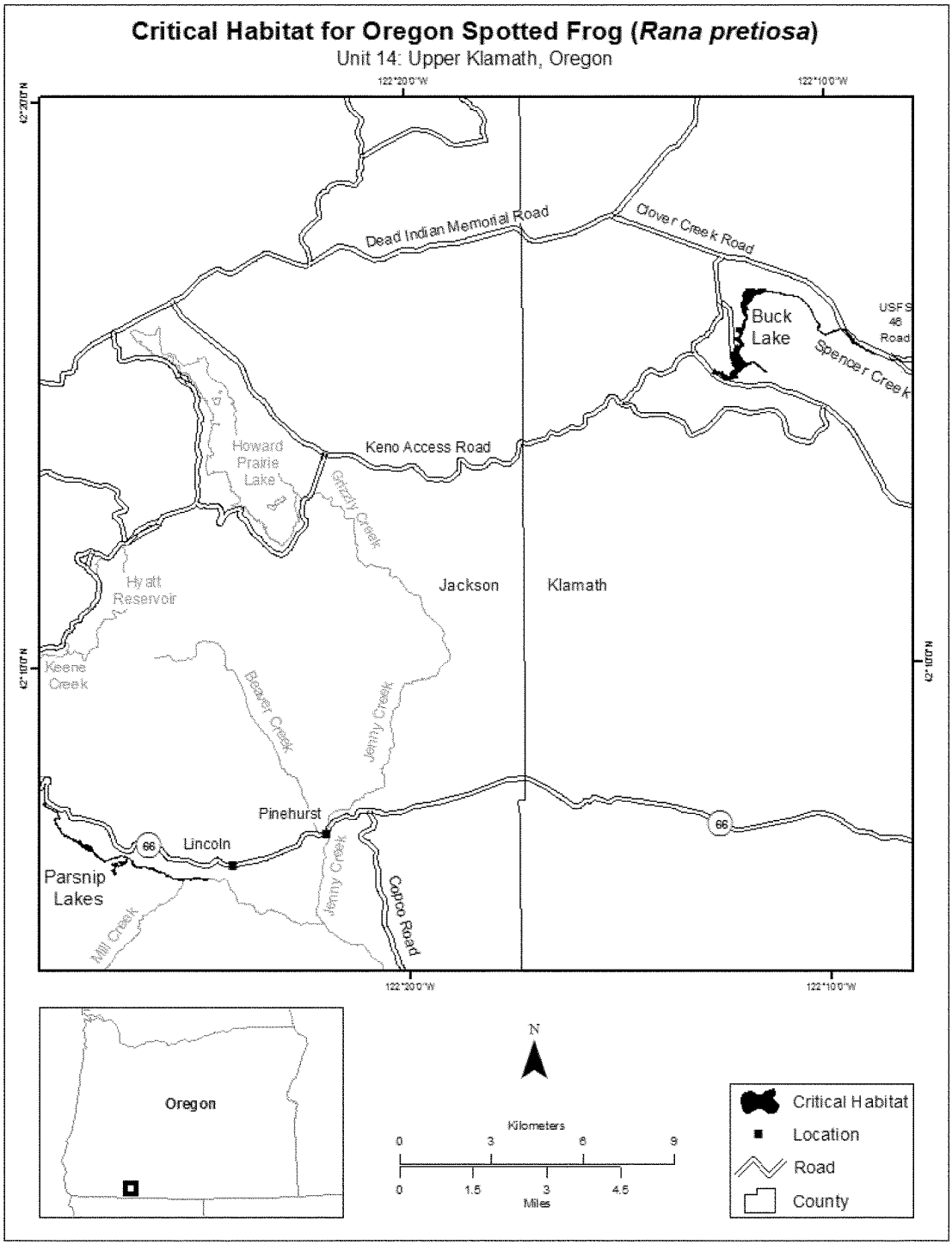
(18) Unit 12: Williamson River, Klamath County, Oregon. Map of Unit 12 follows:



(19) Unit 13: Upper Klamath Lake, Klamath County, Oregon. Map of Unit 13 follows:



(20) Unit 14: Upper Klamath, Jackson and Klamath Counties, Oregon. Map of Unit 14 follows:


Critical Habitat for Oregon Spotted Frog (Rana pretiosa)
Unit 14: Upper Klamath, Oregon
122°20'0"W
122°10'0"W
42°20'0"N
42°10'0"N
Dead Indian Memorial Road
Clover Creek Road
Buck Lake
USFS 46 Road
Spencer Creek
Keno Access Road
Howard Prairie Lake
Grizzly Creek
Hyatt Reservoir
Jackson
Klamath
Keene Creek
Beaver Creek
Jenny Creek
Pinehurst
Lincoln
66
Parsnip Lakes
Mill Creek
Coppo Road
Oregon
N
Kilometers
0 3 6 9
0 1.5 3 4.5
Miles
Critical Habitat
Location
Road
County

* * * * *

Dated: June 10, 2014.

Rachel Jacobson,

Principal Deputy Assistant Secretary for Fish and Wildlife and Parks.

[FR Doc. 2014–14184 Filed 6–17–14; 8:45 am]

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DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 679

[Docket No. 130530519–4476–01]

RIN 0648–BD35

Fisheries of the Exclusive Economic Zone Off Alaska; Bering Sea and Aleutian Islands Management Area; American Fisheries Act; Amendment 106

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

ACTION: Proposed rule; request for comments.

SUMMARY: NMFS issues a proposed rule to implement Amendment 106 to the Fishery Management Plan for Groundfish of the Bering Sea and Aleutian Islands Management Area (BSAI FMP). The proposed rule would allow the owner of an American Fisheries Act (AFA) vessel to rebuild or replace the vessel without limitation on the length, weight, or horsepower of the rebuilt or replacement vessel when the vessel is operating in the Bering Sea and Aleutian Islands Management Area (BSAI). The proposed rule would also allow the owner of an AFA catcher vessel that is a member of an inshore cooperative to remove the vessel from the Bering Sea directed pollock fishery and assign the pollock catch history of the removed vessel to one or more vessels in the inshore cooperative to which the removed vessel belonged. This action is necessary to bring the regulations implementing the BSAI FMP into conformity with the AFA as amended by the Coast Guard Authorization Act of 2010. This action would also improve vessel safety and operational efficiency in the AFA fleet by allowing the rebuilding or replacement of AFA vessels with safer and more efficient vessels and by allowing the removal of inactive catcher vessels from the AFA fishery. This action is intended to promote the goals and objectives of the Magnuson-Stevens Fishery Conservation and Management Act, the AFA, the BSAI FMP, and other applicable laws.

DATES: Submit comments on or before August 4, 2014.

ADDRESSES: You may submit comments, identified by NOAA-NMFS-2013-0097, by any one of the following methods:

- *Electronic Submission:* Submit all electronic public comments via the Federal e-Rulemaking portal. Go to *http://www.regulations.gov/#!docketDetail;D=NOAA-NMFS-2013-0097,* click the ''Comment Now!'' icon, complete the required fields, and enter or attach your comments.
- *Mail:* Address written comments to Glenn Merrill, Assistant Regional Administrator, Sustainable Fisheries Division, Alaska Region NMFS, Attn: Ellen Sebastian. Mail comments to P. O. Box 21668, Juneau, AK 99802.

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. All comments received are a part of the public record and will generally be posted for public viewing on *http://www.regulations.gov* without change. All Personal Identifying Information (for example, name, address) voluntarily submitted by the commenter will be publicly accessible. Do not submit Confidential Business Information or otherwise sensitive or protected information. NMFS will accept anonymous comments (enter N/A in the required fields, if you wish to remain anonymous). Attachments to electronic comments will be accepted in Microsoft Word, Excel, WordPerfect, or Adobe PDF file formats only.

Written comments regarding the burden-hour estimates or other aspects of the collection-of-information requirements contained in this proposed rule may be submitted to NMFS at the above address; emailed to *OIRA_Submission@omb.eop.gov;* or faxed to 202–395–7285.

Electronic copies of Amendment 106 to the FMP, the Regulatory Impact Review/Initial Regulatory Flexibility Analysis (Analysis), and the Categorical Exclusion prepared for this action may be obtained from *http://www.regulations.gov* or from the Alaska Region Web site at *http://alaskafisheries.noaa.gov.*

Additional analyses prepared for the AFA include the Final Environmental Impact Statement (FEIS) for American Fisheries Act Amendments 61/61/13/8 (AFA FEIS) (February 2002); the FEIS for Essential Fish Habitat Identification and Conservation in Alaska (April 2005); the Alaska Groundfish Harvest Specifications—FEIS (January 2007); and the Bering Sea Chinook Salmon Bycatch Management—FEIS (December 2009). These analyses are available on the NMFS Alaska Region Web site at *https://alaskafisheries.noaa.gov/analyses/default.htm.*

FOR FURTHER INFORMATION CONTACT: Mary Alice McKeen, 907–586–7228.

SUPPLEMENTARY INFORMATION: NMFS manages the groundfish fisheries of the BSAI in the Exclusive Economic Zone off Alaska under the BSAI FMP. The North Pacific Fishery Management Council (Council) prepared, and the Secretary of Commerce (Secretary) approved, the BSAI FMP pursuant to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) and other applicable laws. General regulations that pertain to U.S. fisheries appear at subpart H of 50 CFR part 600. Regulations implementing the BSAI FMP appear at 50 CFR part 679. Unless noted otherwise, all references to regulations in this proposed rule are to regulations that are contained in Title 50 of the CFR.

Terms Used in the Preamble

This document uses several terms to help the reader understand the provisions of the proposed rule. The definitions are provided here for ease of reference.

The term ''AFA vessel'' means a vessel that is named on an AFA catcher vessel permit, an AFA catcher/processor permit, or an AFA mothership permit and is authorized by that permit to participate in the directed pollock fishery in the Bering Sea. The proposed rule would add this definition to § 679.2.

The terms ''directed pollock fishery'' or ''AFA fishery'' mean directed fishing for pollock in the Bering Sea subarea. ''Directed fishing'' is defined in regulations at § 679.2.

The term ''original AFA'' means the provisions of the AFA as adopted on October 21, 1998. The original AFA was contained in Division C, Title II—Fisheries, Subtitles I and II, within the Omnibus Appropriations Act FY 1999, Public Law 105–277.

The terms ''amended AFA'' or ''AFA'' mean the American Fisheries Act as amended since 1998, including the amendments to the AFA made by section 602 of the Coast Guard Authorization Act of 2010 (Coast Guard Act), Public Law. 111–281.

The term ''original AFA vessel'' means a vessel that became eligible to participate in the directed pollock fishery under the terms of the original AFA.

Background

The Background portion of this proposed rule contains four sections. Section I describes the relevant statutes and regulations governing the AFA fishery prior to the Coast Guard Act. Section II describes the changes to the AFA made by the Coast Guard Act. Section III describes the history of Council action to address the changes made to the AFA by the Coast Guard Act. Section IV describes the need for this action.

I. Summary of the Original AFA

On October 21, 1998, the President signed into law the original AFA. The original AFA, as adopted in 1998, is available on the NMFS Alaska Region Web site: *https://alaskafisheries.noaa.gov/sustainablefisheries/afa/afa1998.pdf.*

Subtitle I of the original AFA, entitled Fishery Endorsements, comprised sections 201 to 204. Subtitle I made changes generally in the issuance of Federal fishery endorsements by the United States Coast Guard (Coast Guard). These changes were initially codified at 46 U.S.C. 12102 and are now found at 46 U.S.C. 12113. Subtitle II of the original AFA, entitled Bering Sea Pollock Fishery, comprised sections 205 through 213. Subtitle II changed the management of the directed pollock fishery in the BSAI. Subtitle II of the original AFA is codified as a statutory note to section 301 of the Magnuson-Stevens Act (16 U.S.C.A. 1851 note). The following paragraphs briefly describe the provisions in Subtitle I and Subtitle II.

Subtitle I of the Original AFA: Fishery Endorsements

Before the original AFA, a vessel that was five net tons or greater had to have a Federal certificate of documentation with a Federal fishery endorsement to operate as a fishing vessel in U.S. waters (46 U.S.C. 12102(a) (1997); 46 U.S.C. 12108 (1997)). For a vessel to receive a Federal fishery endorsement, the owner of the vessel had to be a U.S. citizen or, if the owner of the vessel was a corporation, the controlling interest in the corporation had to be owned by individuals who were citizens of the United States (46 U.S.C. 12102(c) (1997)).

Subtitle I of the original AFA made two changes in the issuance of Federal fishery endorsements. First, it tightened the requirements for a non-individual entity, such as a corporation, to show that U.S. citizens held a controlling interest in the entity. Subtitle I of the original AFA established a standard of at least 75 percent ownership by U.S. citizens at each tier of ownership of the entity and in the aggregate. For vessels 100 feet or greater in registered length, Subtitle I of the original AFA tasked the Maritime Administration (MARAD), an agency in the Department of Transportation, with making the citizenship determinations for vessel ownership. For vessels less than 100 feet in registered length, the Coast Guard retained the responsibility to make the citizenship determinations for vessel ownership. Subtitle I of the original AFA corrected what Congress believed were mistakes in, and misinterpretations of, the 1987 Commercial Fishing Industry Anti-Reflagging Act. These mistakes and misinterpretations had resulted in the exemption of most vessels from the U.S. citizenship requirements (AFA FEIS at pages 1–3, see **ADDRESSES**).

Second, Subtitle I of the original AFA prohibited the issuance of Federal fishery endorsements to any new fishing vessels that exceeded 165 feet in registered length, that exceeded 750 gross registered tons, or that had an engine or engines capable of producing more than 3,000 shaft horsepower (46 U.S.C. 12113). MARAD regulations refer to vessels that exceed any of these statutory criteria of 165 feet registered length, 750 gross registered tons, or 3,000 shaft horsepower, as ''large vessels'' (46 CFR 356.47). If a vessel was a large vessel, the vessel could not receive a Federal fishery endorsement unless (1) the vessel had a certificate of documentation with a fishery endorsement that was effective on September 25, 1997; or (2) a regional fishery management council recommended and the Secretary of Commerce approved conservation and management measures in accordance with the Magnuson-Stevens Act to allow participation by large vessels in fisheries under the council's authority.

All original AFA vessels had fishery endorsements as of September 25, 1997. Therefore, all original AFA vessels were eligible to receive a Federal fishery endorsement even if the vessel was a ''large vessel.''

Subtitle II of the Original AFA: Bering Sea Pollock Fishery

Subtitle II of the original AFA made sweeping changes in the management of the directed pollock fishery in the BSAI and changed, to a lesser extent, the management of other groundfish fisheries off Alaska. In 2002, NMFS implemented the AFA through the following amendments to fishery management plans: Amendment 61 to the BSAI FMP; Amendment 61 to the Fishery Management Plan for Groundfish of the Gulf of Alaska (GOA FMP); Amendment 13 to the Fishery Management Plan for Bering Sea/Aleutian Islands King and Tanner Crabs; and Amendment 8 to the Fishery Management Plan for the Scallop Fishery off Alaska. NMFS analyzed the impact of the original AFA and the related fishery management plan amendments in the AFA FEIS (see **ADDRESSES**). NMFS published final regulations that fully implemented the original AFA on December 30, 2002 (67 FR 79692).

Subtitle II of the original AFA made five major changes in the management of pollock and other groundfish fisheries off Alaska: (1) Sector allocations, (2) determination of eligible vessels and processors, (3) the allowance of cooperatives; (4) protection measures for other fisheries, and (5) catch weighing and monitoring requirements. These changes are described in detail in the AFA FEIS and are summarized briefly here.

- Sector allocations. The original AFA in section 206 established sector allocations for the BSAI pollock fishery. The original AFA allocated 10 percent of the BSAI pollock total allowable catch (TAC) to the Western Alaska Community Development Quota (CDQ) Program. After allowance for incidental catch of pollock in other fisheries, the original AFA allocated the remaining TAC as follows: a 50 percent allocation to catcher vessels harvesting pollock for processing by the inshore sector; a 40 percent allocation to catcher vessels and catcher/processors harvesting pollock for processing by the catcher/processor sector; and a 10 percent allocation to catcher vessels harvesting pollock for processing by the mothership sector.
- Eligible vessels and processors. The original AFA in section 208 established which vessels and which processors were eligible to participate in the mothership sector, the catcher/processor sector, and the inshore sector. The mothership sector and the catcher/processor sector together make up the offshore component of the Bering Sea pollock fishery. A mothership may only receive and process fish; a catcher/processor may process and harvest fish; a catcher vessel may only harvest fish (section 205 of original AFA).

NMFS initially issued AFA permits to 3 mothership vessels, 21 catcher/processor vessels, and 112 catcher vessels. The three AFA mothership vessels were listed by name as eligible vessels in the AFA. Of the 21 AFA catcher/processors, 20 vessels were listed catcher/processors, which means they were listed by name as eligible in

section 208(e)(1) through (20) of the original AFA. One catcher/processor, although not listed, was eligible because it met the eligibility criteria in section 208(e)(21) of the original AFA. Of the 112 original AFA catcher vessels, 7 vessels were eligible to deliver to the catcher/processor sector only; 6 vessels were eligible to deliver to the mothership sector only; 85 vessels were eligible to deliver to the inshore sector only; and 14 vessels were dual-qualified to deliver in the inshore and mothership sectors (Analysis, Section 1.9.1).

• Cooperatives. The original AFA in section 210 allowed the formation of fishery cooperatives in each AFA sector. Under a fishery cooperative, the members of a cooperative agree to divide up the pollock that the cooperative members may harvest or process in a manner that seeks to eliminate ''a wasteful race for fish'' and to allow participants ''to maximize productivity'' (AFA FEIS, Executive Summary at page 2, see **ADDRESSES**). The original AFA in section 210(b) specifically regulated the formation of inshore cooperatives for catcher vessels. A catcher vessel with an inshore endorsement has a choice to participate in the open access sector and deliver pollock to any AFA inshore processor, or to contribute its catch history to a cooperative and deliver at least 90 percent of its pollock catch to the processor associated with the cooperative (AFA section 210(b); 50 CFR 679.4(l)(6)).

Seven inshore cooperatives have formed (Analysis, Section 1.9.1). Almost all AFA inshore catcher vessels harvest and deliver pollock through a cooperative, rather than in open access. From 2005 to 2014, except for 2010, all inshore catcher vessels fished through a cooperative (Allocations, NMFS Alaska Region Web site, *http://alaskafisheries.noaa/gov/sustainablefisheries/afa).* In 2010, only two inshore catcher vessels fished in open access (Permits, NMFS Alaska Region Web site, *http://alaskafisheries.noaa.gov/ram/afa.htm*).

• Limits on AFA vessels in other fisheries. The original AFA in section 211 provided protections for other fisheries from spillover effects from the allocation of exclusive harvesting privileges in the Bering Sea pollock fishery and the formation of fishery cooperatives. With respect to fisheries outside of Alaska, section 211(b)(5) of the original AFA prohibited AFA catcher/processors and AFA motherships from participating in any fishery outside of Alaska except the Pacific whiting fishery, unless a regional fishery management council specifically authorized such participation.

With regard to fishing in the Exclusive Economic Zone off Alaska, the original AFA provided for limits on AFA vessels that have become known as sideboards. Sideboards are limits on the amount of a species, other than Bering Sea pollock, that AFA vessels may harvest. The original AFA in section 211(b) established sideboard limits in the BSAI and GOA for the 20 catcher/processors that were listed in the original AFA as eligible to participate in the directed pollock fishery. The original AFA in section 211(a) directed the Council to recommend additional sideboard protections. The Council did recommend, and the Secretary approved, a comprehensive set of sideboard regulations on AFA vessels for species other than Bering Sea pollock (see regulations at § 679.64).

The regulations subject most AFA catcher vessels to sideboard limits (§ 679.4). NMFS establishes the sideboard limits, by species, each year through the annual harvest specification process. (See, e.g., Final 2013 and 2014 Harvest Specifications for Groundfish in the GOA, Tables 19 and 20, 78 FR 13162, February 26, 2013). If a sideboard limit for a species is too low to support a directed fishery, NMFS closes the fishery to directed fishing by AFA-sideboarded catcher vessels (§ 679.20(d)(iii) and (iv)). This frequently occurs. For example, in 2013 and 2014, except for pollock and Pacific cod in Western and Central GOA, NMFS closed directed fishing by AFA-sideboarded catcher vessels for almost all other groundfish species in the GOA (Final 2013 and 2014 Harvest Specifications for Groundfish in the GOA, Tables 30 and 31, 78 FR 13162, February 26, 2013).

The regulations exempt some AFA catcher vessels from sideboard limits for BSAI Pacific cod and for GOA groundfish, if the vessels meet specified criteria (§ 679.64(b)(2)). Out of 112 AFA catcher vessels, 10 vessels are exempt from BSAI Pacific cod sideboards and 16 vessels are exempt from GOA sideboards (Analysis, Section 1.9.1). These vessels are known as ''sideboard-exempt'' vessels. Even though exempt from AFA sideboards, the AFA sideboard-exempt vessels are bound by TACs for BSAI Pacific cod and GOA groundfish species and are subject to additional constraints on fishing for these species (Analysis, Section 1.9.1).

• Catch weighing and monitoring requirements. The original AFA in section 211(b)(6) imposed catch weighing and monitoring requirements on the 20 catcher/processors that were listed in the original AFA as eligible to harvest the directed pollock allocation of the catcher/processor sector. The original AFA required the listed catcher/processors to carry two NMFS observers at all times and to weigh all catch on NMFS-approved scales. Through regulations, the Council and NMFS developed catch measurement and observer requirements for all AFA catcher/processors, for AFA motherships, and for AFA catcher vessels (see regulations at § 679.51 and § 679.63).

Original AFA Provisions on Replacing, Rebuilding and Removing AFA Vessels

The original AFA explicitly prohibited the replacement of original AFA vessels except under conditions specified in section 208(g) of the original AFA. The most stringent restriction in section 208(g) was that an owner of an AFA vessel could only replace an AFA vessel in the event of an ''actual total loss or a constructive total loss'' of the original AFA vessel. The original AFA did not specifically define total loss or constructive loss, but the terms are commonly used in maritime insurance. A total loss usually means that the vessel sinks, or is otherwise destroyed, and is physically lost. A constructive loss usually means that a vessel is so damaged that the cost of repair is greater than the value of the vessel. Thus, under the original AFA, a vessel owner could not replace an original AFA vessel until the AFA vessel sunk or was so damaged that it could not economically be repaired. An AFA vessel owner could not replace an original AFA vessel with another vessel simply because the vessel owner wanted a vessel that was safer, more fuel-efficient, or more operationally efficient than the owner's current vessel in any way.

Further, if an original AFA vessel owner did lose an original AFA vessel, section 208(g) of the original AFA limited the length, tonnage, and horsepower of the replacement vessel. If the original AFA vessel was a large vessel, the replacement vessel could not exceed the length, tonnage, or horsepower of the original AFA vessel. If the original AFA vessel was less than any of the statutory thresholds, the replacement vessel could exceed the length, weight, or horsepower of the original AFA vessel by 10 percent, but only up to the statutory thresholds for large vessels.

Between 1998 and passage of the Coast Guard Act in 2010, NMFS approved the replacement of four original AFA vessels under the standards in the original AFA. All

replaced vessels were catcher vessels. Two replacement vessels were new to the AFA fishery. Two replacement vessels already were original AFA vessels that replaced other original AFA vessels.

The original AFA had no explicit provisions on rebuilding original AFA vessels. The original AFA did not provide a mechanism for a vessel owner to remove an original AFA vessel from the directed pollock fishery.

Effect of License Limitation Program (LLP) on Rebuilding and Replacing Original AFA Vessels

To participate in the directed pollock fishery in the Bering Sea, an AFA vessel must not only have an AFA permit, but must also be named on an LLP license with a Bering Sea area endorsement. There are two sources for this requirement. First, section 208(a)(2) of the original AFA specifically stated that to be eligible to participate in the directed pollock fishery, a vessel had to be eligible to harvest pollock under the LLP. Second, pollock is a license limitation groundfish (§ 679.2) and to conduct directed fishing for any species of license limitation groundfish in the Bering Sea, a vessel must be named on an LLP groundfish license with a Bering Sea area endorsement (§ 679.4(k)(1)(i)).

Further, AFA vessels harvest pollock with trawl gear. Every LLP license has a gear designation of either trawl gear, trawl/non-trawl gear, or non-trawl gear (§ 679.4(k)(1)(iv)). The first two gear designations—trawl and trawl/non-trawl—authorize the vessel named on the LLP license to use trawl gear. Therefore, to effectively fish for pollock, an AFA vessel must have an LLP license with a gear designation for trawl gear or trawl/non-trawl gear.

The requirement that an AFA vessel have an LLP license limits the ability of owners of AFA vessels to rebuild or replace AFA vessels. All LLP licenses specify a maximum length overall or MLOA (§ 679.4(k)(3)(i)). Under existing regulations, a vessel fishing for groundfish pursuant to an LLP license cannot exceed the MLOA on that license (§ 679.4(k)(1)(i), § 679.7(i)(6)). Therefore, under existing LLP regulations, an AFA vessel can only fish for Bering Sea pollock if, after rebuilding or replacement, (1) the AFA vessel is designated on an LLP license with a Bering Sea area endorsement and a gear designation authorizing trawl gear and (2) the AFA vessel does not exceed the MLOA on that LLP license.

Aleutian Islands Directed Pollock Fishery

The original AFA applied to the directed pollock fishery in the entire BSAI Management Area (section 205(4), section 205(6), section 205(10) of original AFA). The BSAI Management Area consists of the Bering Sea Subarea and the Aleutian Islands Subarea (see regulatory definitions in § 679.2). In 2004, Congress adopted section 803 of Public Law 108–199, which was the Consolidated Appropriations Act, 2004. In this statute, Congress allocated the directed pollock fishery in the Aleutian Islands (AI) to the Aleut Corporation and specified criteria for vessels to be eligible to harvest that allocation. NMFS published regulations implementing this statute in 2005 (70 FR 9856, March 1, 2005).

Within statutory and regulatory restrictions, the Aleut Corporation may annually select the participants in this fishery (§ 679.4(m), § 679.20(a)(5)(iii)(B)(*5*)). If the Aleut Corporation does not select participants, or if, for any reason, NMFS determines that the vessels in the AI directed pollock fishery will not likely harvest the TAC allowed in that fishery, NMFS may reallocate the TAC for that year in the AI directed pollock fishery to the Bering Sea pollock fishery (§ 679.20(a)(5)(iii)(B)(*2*)(*ii*)). The amended AFA and this proposed rule do not change any statutory or regulatory provisions that pertain to the AI directed pollock fishery. The amended AFA and this proposed rule do not limit the authority of the Aleut Corporation to select participants in the AI directed pollock fishery within the constraints of Public Law 108–199 and regulations implementing that statute.

II. Summary of the AFA as Amended by the Coast Guard Act

On October 15, 2010, Congress amended the AFA in section 602 of the Coast Guard Act, Public Law 111–281. The Coast Guard Act revised section 208(g) of the AFA to essentially eliminate all restrictions on the ability of the owners of AFA vessels to rebuild or replace AFA vessels when the vessel participates in groundfish fisheries of the BSAI. Under the amended AFA, the owner of an AFA vessel may rebuild that vessel or replace that vessel in order to improve vessel safety and operational efficiencies, including fuel efficiency. The amended AFA removes the statutory limits on the length, tonnage, or horsepower of the rebuilt or replacement vessel when the rebuilt or replacement vessel is participating in BSAI groundfish fisheries. In addition, section 208(g) of the AFA, as revised, removes the MLOA limitation in the LLP on the length of an AFA rebuilt or replacement vessel when the vessel participates in BSAI groundfish fisheries.

With respect to the Gulf of Alaska (GOA), section 208(g)(6) of the AFA, as revised, preserves the MLOA limitation in the LLP on the length of an AFA vessel when the vessel participates in GOA groundfish fisheries. An AFA vessel—whether an original AFA vessel, a rebuilt AFA vessel, or a replacement AFA vessel—may not conduct directed fishing for groundfish in any area in the GOA if the vessel exceeds the MLOA on the LLP groundfish license that is endorsed for that area and that is assigned to that vessel.

With respect to participation in fisheries outside of Alaska, the original AFA in section 211(b)(5) prohibited an AFA catcher/processor or AFA mothership from harvesting or processing fish in any fishery outside of Alaska except the Pacific whiting fishery. The amended AFA in section 208(g)(1)(B) imposes that prohibition on rebuilt and replacement AFA catcher/processors and motherships because it subjects AFA rebuilt and replacement vessels to the same restrictions as the vessel being rebuilt or replaced. While the original AFA did not prohibit an AFA catcher vessel from harvesting fish in fisheries outside of Alaska, the amended AFA in section 208(g)(4) imposes a prohibition on AFA rebuilt or replacement catcher vessels similar to the prohibition that applied to AFA mothership vessels and listed AFA catcher/processors in section 211(b)(5) of the original AFA. Under the amended AFA, a rebuilt or replacement AFA catcher vessel is prohibited from harvesting fish in any fishery outside of Alaska except for the Pacific whiting fishery.

The provisions discussed thus far describe the fishing privileges of the AFA rebuilt vessel and the AFA replacement vessel. The other side of the coin is what happens to the vessel that is replaced: the vessel that leaves the AFA fishery and is replaced by another vessel in the AFA fishery. Under section 211(b)(5) of the amended AFA, a vessel that is replaced is not eligible for a Federal fishery endorsement under 46 U.S.C. 12113 unless the replaced vessel becomes, in the future, a replacement vessel for another vessel leaving the AFA fishery.

The amended AFA added section 210(b)(7) to the AFA. This new provision allows the owner of an AFA catcher vessel that is a member of an inshore cooperative to remove the

catcher vessel from the inshore cooperative. Under section 210(b)(7), the owner of the removed vessel must assign the catch history of the removed vessel to one or more vessels in the cooperative to which the removed vessel belonged. Under section 210(b)(7), the vessels that are assigned the pollock catch history of the removed vessel must stay in the fishery cooperative for at least one year after the date on which the vessel was removed from the cooperative. Except for the assignment of the pollock catch history of the removed vessel, section 210(b)(7)(B) permanently extinguishes any claim that might have been based on the catch history of the removed vessel. This means that if the removed AFA catcher vessel was exempt from any sideboard limitations, NMFS permanently extinguishes the exemption and does not assign it to any other vessel.

Finally, except for four named vessels, section 210(b)(7)(B) of the amended AFA prevents the owner of an AFA catcher vessel that is removed under this provision from using the removed vessel in other fisheries. The amended AFA accomplishes this by making a removed AFA catcher vessel permanently ineligible for a Federal fishery endorsement, except that a removed AFA vessel may receive a Federal fishery endorsement to reenter the AFA fishery as a replacement vessel.

The four vessels are named in section 210(b)(7)(C) of the amended AFA. These vessels, if removed, may receive a Federal fishery endorsement to participate in a fishery under the authority of the New England Fishery Management Council or the Mid-Atlantic Fishery Management Council. These vessels are the *AJ* (U.S. official number 905625), *Dona Martita* (U.S. official number 651751), *Nordic Explorer* (U.S. official number 678234), and *Providian* (U.S. official number 1062183).

The Coast Guard, in conjunction with MARAD, will issue Federal fishery endorsements in accord with the amended AFA. For information on the vessel documentation process, see the Coast Guard Web site for the National Vessel Documentation Center at *http://www.uscg.mil/hq/cg5/nvdc/.*

III. History of Council Action

Section 208(g)(2) of the amended AFA gave the Council authority to recommend additional conservation and management measures if the Council concluded that such measures were necessary to ensure that the amended AFA did not undermine the effectiveness of the fishery management plans for either the BSAI or the GOA. Pursuant to section 208(g)(2) of the amended AFA, the Council reviewed whether to recommend conservation and management measures for the GOA, in addition to the restrictions on fishing by AFA vessels in the GOA in existing regulations. The Council concluded that additional measures for the GOA were not necessary, in light of the protections for GOA participants provided by current management measures.

The history of Council action on this subject is documented in minutes and newsletters of Council meetings, which are on the Council Web site: *https://alaskafisheries.noaa.gov/npfmc.* At its February 2012 meeting, the Council received a discussion paper on the issues raised by the AFA amendments and directed staff to analyze alternatives to limit the participation by AFA rebuilt and replacement vessels in the GOA beyond the limitations already in the AFA amendments. At its October 2012 meeting, the Council reviewed a draft analysis and directed staff to make changes in light of comments by the Council's Scientific and Statistical Committee.

At its February 2013 meeting, the Council reviewed the revised analysis. The Council approved the revised analysis for public review and adopted a preliminary preferred alternative. The Council's preliminary preferred alternative was Alternative 2, namely that NMFS should revise the relevant fishery management plans and regulations in accord with the AFA amendments, as NMFS planned to implement the AFA amendments, and that the Council did not need to recommend additional measures for the GOA. The other alternatives considered by the Council—Alternatives 2.1, 2.2, 2.3, and 2.4—placed additional restrictions on AFA rebuilt and replacement vessels when they participated in the GOA. At its April 2013 meeting, the Council unanimously adopted Alternative 2 as its preferred alternative.

In describing Alternative 2, the Analysis described how NMFS would implement the AFA amendments, if the Council did not recommend any additional conservation and management measures (Analysis, Executive Summary at pages ix–xv). The Analysis describes four key areas of NMFS' implementation of the AFA amendments under Alternative 2. First, under Alternative 2, the owner of an AFA vessel would be able to rebuild or replace the vessel with no limitation on the length, size, or horsepower of the rebuilt or replacement vessel, when the rebuilt or replacement vessel was participating in the BSAI (section 208(g)(1)(A) of amended AFA).

Second, with respect to the participation by AFA vessels in the GOA, the AFA amendments preserve the Maximum Length Overall (MLOA) restriction in the LLP for AFA rebuilt and replacement vessels when these vessels participate in the GOA (section 208(g)(6) of amended AFA). To participate in the GOA, AFA vessels must have an LLP license with an area endorsement for the Central Gulf or Western Gulf area (§ 679.4(k)(4)(ii)). An LLP license for the GOA may also have a Southeast Outside area endorsement but AFA vessels use trawl gear and trawl gear is prohibited in Southeast Outside (§ 679.22(b)(4)). Thus, under the AFA amendments as described in Alternative 2 in the Analysis, to fish for groundfish in the GOA, an AFA vessel 1) must have an LLP license with an area endorsement for Western Gulf or Central Gulf and 2) must not exceed the maximum length overall on that LLP license when the vessel is fishing pursuant to that license (Analysis, Executive Summary at page x). A vessel's LLP license endorsed for the Bering Sea is irrelevant to what the vessel can and cannot do in the GOA.

Third, the AFA amendments allow the owner of an AFA catcher vessel that is a member of an inshore cooperative to remove the vessel from the inshore cooperative and to assign the pollock fishing allowance of the removed vessel to one or more vessels in the same inshore cooperative (section 210(b)(7) of amended AFA). Fourth, and related, NMFS concludes that the AFA amendments require that NMFS extinguish any sideboard exemptions of a removed catcher vessel. The AFA amendments provide that, except for the claim to the pollock fishing allowance of the removed vessel, NMFS must extinguish ''any claim (including relating to catch history)'' of the removed vessel (section 210(b)(7)(B) of amended AFA). If the removed vessel was exempt from AFA sideboard limitations, the exemption was based on the vessel's catch history (§ 679.64(b)). A sideboard exemption is clearly a claim ''relating to [the vessel's] catch history.'' Therefore, if the removed vessel was exempt from sideboard limitations, the AFA amendments require NMFS to extinguish that exemption and prohibit NMFS from assigning that sideboard exemption to any other vessel or vessels. (Analysis, Executive Summary at page xv).

The Council specifically concurred with NMFS' interpretation of this provision in the AFA amendments (Analysis, Executive Summary at page

xx). The Council further concluded that, if NMFS did not implement the AFA amendments this way, the Council would recommend this action—extinguishment of the sideboard exemptions of a removed vessel—as a conservation and management measure necessary to ensure that the AFA amendments did not diminish the effectiveness of fishery management plans of the BSAI or GOA (Analysis, Executive Summary at page xx).

As for whether any other measures were necessary to protect the GOA, the Council concluded that no other measures were necessary. The Council noted the considerable protections already in place that restrict fishing by AFA vessels in the GOA. The Council relied on these measures to conclude that current management measures provided sufficient protection for participants in the GOA from increased activity from AFA rebuilt and replacement vessels.

The Analysis describes the existing limitations on AFA vessels in the GOA: the limited number of LLP licenses with Central Gulf or Western Gulf endorsements; the sideboard limits on GOA species that apply to most AFA vessels; the sideboard limits in the Central GOA Rockfish Program for AFA sideboard-exempt vessels that participate in that program; limitations on the use of AFA catcher vessels that operate in both the BSAI and GOA (commonly known as a ''stand-down'' requirement); exclusive fishing seasons for AFA catcher vessels that participate in the pollock fisheries in the BSAI and GOA; trip limits for pollock that are part of the Steller sea lion mitigation measures; limits on AFA trawl catcher vessels operating as pollock tenders; and the provision in the Inter-Cooperative Agreement that prevents an AFA-sideboard exempt vessel from leasing its pollock quota in a year once the vessel exceeds its GOA average harvest level from the 1995 through 1997 period (Analysis, Section 1.9.1 and Section 1.11.2).

A further restriction on AFA vessels in the GOA is the Pacific cod sector split. Beginning in 2012, NMFS annually allocates Pacific cod in the GOA by gear type and vessel type. The sector split allocates Pacific cod to the hook-and-line sector, the pot sector, and the trawl sector. Since AFA vessels use trawl gear to harvest pollock, and since the other gear sectors have their own Pacific cod allocation, the sector split restricts the harvest of Pacific cod in the non-trawl fisheries in the GOA by AFA vessels. For additional detail on the GOA Pacific cod sector split, see the final rule implementing this measure (76 FR 74670, December 2, 2011).

The Council relied on the current suite of restrictions on the participation by AFA vessels in the GOA when the Council did not adopt an alternative that limited participation by AFA vessels in the GOA beyond the restrictions in current statute and regulation.

As for the BSAI, and whether any additional measures were necessary to restrict fishing by AFA vessels in the BSAI, the Council did not specifically consider an alternative to limit non-pollock fishing by AFA rebuilt and replacement vessels in the BSAI beyond the restrictions currently in place. However, the Analysis presented to the Council did describe in detail the extent of fishing by AFA vessels in the BSAI in non-pollock fisheries and did describe the stringent sideboard limits and closures that restrict most AFA vessels (Analysis, Tables 1–1, 1–2, 1–5, 1–8, 1–9, 1–14, 1–15, 1–18. 1–19, 1–23, and Section 1.9.1).

The only AFA vessels that are exempt from any sideboard limits in the BSAI are 10 AFA catcher vessels that are exempt only from BSAI Pacific cod sideboard limits. These 10 sideboard-exempt vessels are, of course, subject to the TAC limits for BSAI Pacific cod and all other species they harvest. Furthermore, the AFA sideboard-exempt vessels in the BSAI are subject to many of the restrictions, noted above, that apply to AFA vessels in the GOA, including stand-down requirements for AFA catcher vessels that operate in both the BSAI and GOA; exclusive fishing seasons for AFA catcher vessels that participate in the pollock fisheries in the BSAI and GOA; and limits on AFA trawl catcher vessels from operating as pollock tenders (Analysis, Section 1.9.1 at pages 20–22).

Thus, with respect to the BSAI, the Council had before it considerable information regarding non-pollock fishing by AFA vessels in the BSAI and did not recommend any management measures beyond the limits on AFA vessels in existing regulations.

IV. The Need for Action

The BSAI FMP and current regulations are consistent with the original AFA, but not with the amended AFA. On this basis, the need for action is clear. The BSAI FMP and regulations must be changed to conform to a statute adopted by Congress.

This action is needed not only to implement the amended AFA, but also to further the purpose of the AFA amendments themselves. The primary purpose of the Coast Guard Act amendments to the AFA is to promote the safety and efficiency of the AFA fleet by allowing the owners of AFA vessels to rebuild or replace their vessels. Under the original AFA and existing regulations, an owner of an AFA vessel had to wait until the vessel sank or was damaged beyond repair before the owner of an AFA vessel could replace the AFA vessel with another vessel. The AFA fleet is aging. Of the 92 AFA catcher vessels active in the inshore and mothership sectors in 2011, all were built before 1992. Sixty were built before 1980 (Analysis, Table 1–7). Of the 21 catcher/processors with AFA permits, all were built before 1990. Fifteen were built before 1980 (Analysis, Table 1–26).

Under the original AFA, as reflected in current regulations, an owner of an AFA vessel cannot replace an AFA vessel with a vessel that is safer, more fuel efficient, or more operationally efficient in other ways. For example, the Analysis notes that advances in propulsion systems for catcher vessels, when paired with improved hull forms, can result in gains in fuel efficiency of up to 25 percent or more per pound of fish products delivered (Analysis, Section 1.11.2).

Under the original AFA, the rebuilding or replacement of AFA vessels was limited by length, tonnage, and horsepower of the rebuilt or replacement vessel. Under the amended AFA, the owner of an AFA vessel may rebuild that vessel or replace that vessel with no limit on the length, tonnage, or horsepower of the rebuilt or replacement vessel when the rebuilt or replacement vessel is participating in the BSAI. The removal of these limits could substantially improve the operational efficiency of AFA vessels. For example, the Analysis notes that the owners of smaller and older AFA catcher/processors may wish to rebuild or replace their vessels to install a fish meal plant, which would enable them to sell fish meal and fish oil. Vessels may also use fish oil as fuel in hybrid diesel electric engines and reduce costs from purchasing petroleum-based fuel (Analysis, Section 1.11.2).

The proposed rule would not require an AFA vessel owner to upgrade a vessel. An AFA vessel owner still must find that the improved safety and improved efficiency from rebuilding or replacing is worth the cost. The Analysis does not try to estimate how many owners of AFA catcher vessels, catcher/processors, or motherships will rebuild or replace vessels. The likelihood of a given vessel being rebuilt or replaced will depend on many factors, including the financial

resources of the vessel owner, which is proprietary and confidential information. NMFS does not have that information and therefore cannot reliably estimate how many AFA vessel owners would rebuild or replace their vessels under the proposed rule. The proposed rule would, however, allow the owners of AFA vessels to weigh the costs and benefits of rebuilding or replacing their vessels, and to act on their evaluation, before their vessels sink or are damaged beyond repair.

Finally, this action responds to the problem that owners of catcher vessels in the inshore sector have experienced because the AFA had no provisions allowing for removal of vessels from the AFA fishery. Under existing regulations, the catcher vessels that do not actively fish for the cooperative must be tied up at the dock or put in storage, even if the owner has concluded that the vessel will never fish again. Except when a vessel was lost, the original AFA provided no way for the owner of an AFA inshore catcher vessel to transfer the catch history of one inshore catcher vessel to any other inshore catcher vessel. The owner of an AFA inshore catcher vessel could not do that simply because the owner wished to remove the vessel from the fishery.

The inability of the owner of an AFA inshore catcher vessel to remove a vessel from the AFA fishery results from the requirement in the original AFA and AFA regulations for a vessel to be a member of an inshore cooperative. For each year the owner of a catcher vessel wants to be a member of a particular inshore cooperative, the catcher vessel must be a ''qualified catcher vessel'' for membership in that inshore cooperative. (Original AFA, section 211(b)(3); 50 CFR 679.4(l)(6)(ii)(*D*)). To be a qualified catcher vessel, a catcher vessel must be eligible to harvest pollock in the Bering Sea and must be eligible to harvest groundfish in BSAI (§ 679.4(l)(1)(i); § 679.4(l)(6)(ii)(C)(*3*)). This means that, to be a member of an inshore cooperative, a catcher vessel must exist and must be designated on four permits: a Federal Fisheries Permit, an AFA catcher vessel permit with an inshore endorsement, an LLP groundfish license with a Bering Sea endorsement, and, of course, an inshore cooperative permit (§ 679.4(l)(6)).

Even though every catcher vessel in an inshore cooperative must be eligible to fish for pollock and for groundfish under the original AFA, not every catcher vessel in an inshore cooperative must actually fish for the cooperative. Some catcher vessels in a cooperative do not fish at all, or fish very little. Other, more efficient, catcher vessels in the cooperative harvest the pollock that the cooperative is authorized to catch. Some of the catcher vessels that do not fish are obsolete and inefficient, but under the original AFA and existing regulations, the owners of these vessels have no way to remove them from the AFA fishery. The AFA amendments and the proposed rule remedy this deficiency by allowing the owner of a catcher vessel that is a member of an inshore cooperative to remove that vessel from the AFA fishery subject to the conditions described above in Section II, ''Summary of the AFA as amended by the Coast Guard Act.''

Proposed Action

This proposed rule would revise the current regulations to implement the amended AFA and Amendment 106 to the BSAI FMP. This proposed rule addresses the rebuilding, replacement, and removal of AFA vessels and would make the following changes.

AFA Rebuilt Vessels

This proposed rule would establish the procedure for owners of AFA rebuilt vessels to maintain AFA permits on rebuilt vessels, would define the fishing privileges of the rebuilt vessel, and would modify the LLP regulations for AFA rebuilt vessels.

• Procedure. The proposed rule at § 679.4(l)(7)(i) would establish a procedure for the owners of AFA rebuilt vessels to maintain AFA permits for AFA rebuilt vessels. Under the proposed rule, an owner of an AFA vessel may rebuild the AFA vessel to improve the safety of the vessel or the operational efficiency of the vessel including the fuel efficiency of the vessel. When a vessel owner applies for an AFA permit or LLP license for a rebuilt vessel, NMFS will ask the applicant to certify that the purpose of the rebuilding was to improve safety, improve operational efficiency, or both.

In the application process, NMFS would not undertake to substantiate that the owner rebuilt the AFA vessel for the reason stated in the application. Similarly, NMFS would not undertake to substantiate through the application process that the rebuilt vessel was safer or more efficient. It would be difficult to establish a standard for judging whether a rebuilt or replacement vessel was safer or more efficient. NMFS does not believe that was the intent of Congress in amending the AFA. NMFS concludes that the purpose of the amended AFA is to allow the owner of an AFA vessel to weigh the considerable costs in rebuilding an AFA vessel against the benefits and to proceed if the owner determined the benefits were worth the costs.

To maintain an AFA permit, the AFA rebuilt vessel must have a certificate of documentation with a Federal fishery endorsement. If the owner of an AFA vessel rebuilds an AFA vessel, the proposed rule at § 679.4(l)(7)(i) would require that the owner notify NMFS and provide a copy of the documentation of the rebuilt vessel within 30 days of the issuance of the documentation. The 30-day period would provide adequate time for the applicant to notify NMFS.

• Fishing privileges of AFA rebuilt vessels. Under the proposed rule at § 679.4(l)(7)(i)(B), the owner of an AFA rebuilt vessel would be eligible to use the vessel in the same manner as the vessel before rebuilding and would be subject to the same requirements under 50 CFR part 679 that applied to the vessel before rebuilding, except for two requirements. First, under the proposed rule at § 679.4(l)(7)(i)(C), an AFA rebuilt vessel would be exempt from the MLOA requirement on an LLP groundfish license with a Bering Sea endorsement or an Aleutian Islands endorsement when that vessel is fishing for groundfish in the BSAI pursuant to that license, whether or not the vessel, before rebuilding, was exempt from the MLOA requirement. This exemption from the MLOA requirement for AFA rebuilt (and replacement) vessels implements a key feature of the AFA amendments.

The exemption from the MLOA requirement would attach to any AFA vessel that was rebuilt after October 15, 2010, the effective date of the Coast Guard Act. The exemption would remain with the vessel. That is, under the proposed rule, once an AFA vessel is rebuilt, the vessel would be permanently exempt from the MLOA restriction on any LLP license with a Bering Sea or Aleutian Islands area endorsement on which the vessel is designated when the vessel is fishing for groundfish in the BSAI pursuant to that LLP license.

The second area where an AFA rebuilt vessel would be subject to a different requirement from the AFA vessel before rebuilding relates to the fishing restrictions in § 679.23(i). A little background is necessary to understand the issue. For certain species in the BSAI or GOA, § 679.23 divides a fishing year into seasons. Section 679.23 divides directed fishing for pollock in the BSAI into two seasons (A season and B season) and divides directed fishing for pollock in the GOA into four seasons (A season, B season, C season, and D season). Section 679.23(i) imposes restrictions that prevent catcher

vessels from fishing for pollock in every season in every year in the BSAI and GOA. For example, under this regulation, if a catcher vessel fishes for pollock in the BSAI in the A season, the catcher vessel cannot fish for pollock in the GOA until the start of the following C season.

Section 679.23 is an inseason management tool to lessen competitive interactions between the groundfish fisheries and Steller sea lions. Section 679.23 ''limits the concentration of fishing effort in one area and reduces the potential for localized depletion of Steller sea lion prey'' (Analysis, section 1.9.1 at page 39). However, § 679.23(i) exempts catcher vessels that are less than 125 feet LOA from the season restrictions in the regulation when the vessels are fishing east of 157°00′ W. long.

NMFS considered whether an AFA rebuilt catcher vessel that is 125 feet LOA or greater after rebuilding would remain subject to the restrictions in § 679.23, even if the vessel was less than 125 feet LOA before rebuilding and therefore was not subject to the restrictions in § 679.23. Under the AFA amendments, NMFS concludes that an AFA rebuilt vessel that is 125 feet LOA or greater is subject to the restrictions in § 679.23. Thus, under the proposed rule at § 679.4(l)(7)(i)(D), an AFA rebuilt catcher vessel that is 125 feet LOA or greater would be subject to the fishing restrictions in § 679.23, even if the vessel before rebuilding was not subject to the restrictions in § 679.23.

NMFS bases this provision in the proposed rule—the continuation of the restrictions in § 679.23 on AFA rebuilt (and replacement) vessels—on three things: the language of the amended AFA, the purpose of the restrictions in § 679.23, and the Analysis for this action.

First, the amended AFA in section 208(g)(1)(A) states that ''[n]otwithstanding any limitation to the contrary on replacing, rebuilding, or lengthening vessels, or transferring permits or licenses to a replacement vessel contained in section 679.2 and 679.4 [of Title 50 CFR],'' a vessel owner may rebuild or replace an AFA vessel. The restriction in § 679.23 is not in § 679.2 or § 679.2 of Title 50 CFR and is therefore not abrogated by reference in section 208(g)(1)(A). Further, the restriction in § 679.23 is not a ''limitation . . . on replacing, rebuilding or lengthening'' AFA vessels. The proposed rule would still allow the owner of an AFA vessel to rebuild or replace an AFA vessel without limitation on the length of the vessel when it is fishing in the BSAI.

The amended AFA in section 208(g)(1)(B) states that the rebuilt and replacement vessel will be ''subject to the same restrictions and limitations . . . as the vessel being rebuilt or replaced.'' The amended AFA in section 208(g)(1)(C) states that the rebuilt and replacement vessel should receive the permits ''as necessary . . . to operate in the same manner'' as the vessel prior to rebuilding or replacement. If the AFA vessel, prior to rebuilding or replacement, had been lengthened so that it was 125 feet LOA or greater, the AFA vessel would have been subject to the restrictions in § 679.23. NMFS concludes that subjecting an AFA rebuilt vessel to the restrictions in § 679.23 is subjecting an AFA rebuilt vessel to ''the same restrictions and limitations'' that applied to the vessel before rebuilding and is allowing the AFA rebuilt vessel to ''operate in the same manner'' as the vessel could have operated before rebuilding.

Second, as noted, the purpose of § 679.23 is to lessen competition between the groundfish fisheries and the Steller sea lion population. NMFS concludes that the purpose of the AFA amendments was not to lessen the scope of the protective measures for the Steller sea lion population in § 679.23. Specifically, NMFS concludes that the purpose of the AFA amendments was not to grant more fishing opportunities to AFA vessels that become 125 feet LOA or longer through rebuilding as opposed to AFA vessels that are 125 feet or longer not as a result of rebuilding.

Finally, the Analysis describes the restrictions in § 679.23 on fishing by AFA vessels as part of Alternative 2, the Council's preferred alternative (Analysis, Section 1.9.1 at pages 39–40). In deciding not to recommend additional measures to limit AFA rebuilt and replacement vessels, the Council relied on this and other measures that currently limit the participation of AFA vessels in the BSAI and GOA. For these reasons, the proposed rule would keep in place the restrictions in § 679.23 that apply to AFA vessels that are 125 feet LOA or longer, even if the AFA vessel was less than 125 feet LOA before rebuilding.

• Changes in LLP regulations for AFA rebuilt vessels. The proposed rule would modify the LLP regulations at § 679.2 and § 679.4(k). The proposed rule modifies these regulations to provide that an AFA rebuilt vessel is exempt from the MLOA requirement on an LLP groundfish license with a Bering Sea or Aleutian Islands area endorsement assigned to the vessel when the vessel is fishing for groundfish in the BSAI and when the LLP license specifies the exemption.

The LLP license holder that wishes to designate an AFA rebuilt vessel on an LLP license is still subject to a limit of one voluntary transfer per year of an LLP license (§ 679.4(k)(7)(vi)). A change of the vessel designated on an LLP license is treated as a voluntary transfer of an LLP license (§ 679.4(k)(7)(vii)).

AFA Replacement Vessels

This proposed rule would establish the procedure for the owner of an AFA vessel to obtain an AFA permit for a replacement vessel, would define the fishing privileges of the replacement vessel, and would modify the LLP regulations for AFA replacement vessels.

• Procedure. Under the proposed rule at § 679.4(l)(7)(ii), an owner of an AFA vessel may replace an AFA vessel with another vessel to improve vessel safety or to improve operational efficiency, including fuel efficiency. To do that, the owner of an AFA vessel would have to submit an application to NMFS that would (1) identify a replacement vessel, (2) provide vessel documentation for the replacement vessel, (3) show that the replacement vessel has a Federal fishery endorsement, and (4) identify the LLP groundfish license on which the AFA replacement vessel would be designated.

On NMFS's approval of the application to replace the AFA vessel with another vessel, the AFA permit that designated the former, or replaced, vessel would be revoked and NMFS would issue a new AFA permit to the replacement vessel, unless the replacement vessel already had an AFA permit.

• Fishing privileges of AFA replacement vessels. The owner of the AFA replacement vessel would be eligible to use the AFA replacement vessel in the same manner as the AFA replaced vessel, and the AFA replacement vessel would be subject to the same requirements under 50 CFR part 679 that applied to the AFA replaced vessel, except for three requirements.

First, under the proposed rule at § 679.4(l)(7)(ii)(C), the AFA replacement vessel would be exempt from the MLOA on an LLP groundfish license with a Bering Sea or Aleutian Islands endorsement on which the replacement vessel is designated when the vessel is fishing pursuant to that LLP license, even if the replaced vessel was not exempt. As with AFA rebuilt vessels, the MLOA exemption would attach to a vessel that became an AFA replacement vessel after October 15, 2010, the

effective date of the AFA amendments in the Coast Guard Act, and would remain with the vessel.

Second, under the proposed rule at § 679.4(l)(7)(ii)(D), an AFA replacement vessel that exceeds 125 feet LOA would be subject to the fishing restrictions in § 679.23(i), even if the replaced or departing vessel was less than 125 feet and was exempt from these restrictions. This is the same provision that would apply to AFA rebuilt vessels under the proposed rule. The rationale for this provision is thoroughly explained in the previous section, ''Fishing Privileges of AFA rebuilt vessels.''

Third, under the proposed rule at § 679.4(l)(7)(ii)(E), if the AFA replacement vessel was already an AFA-permitted catcher vessel with a sideboard exemption, and the replaced or departing vessel was an AFA catcher vessel without a sideboard exemption, the replacement vessel would maintain the sideboard exemption. The replacement vessel would not lose an exemption by virtue of acquiring the pollock catch history of a vessel that did not have an exemption.

- Changes in LLP regulations for AFA replacement vessels. As with AFA rebuilt vessels, the proposed rule would modify the LLP regulations at § 679.2 and § 679.4(k). The proposed rule would modify these rules to provide that an AFA replacement vessel is exempt from the MLOA requirement on an LLP groundfish license with a Bering Sea or Aleutian Islands area endorsement assigned to the vessel when the AFA replacement vessel is fishing for groundfish in the BSAI pursuant to that LLP license and when the LLP license specifies the exemption.

The LLP license holder that wishes to designate an AFA replacement vessel on an LLP license is still subject to the limit in current regulation of one voluntary transfer per year of an LLP license (§ 679.4(k)(7)(vi)). A change of the vessel designated on an LLP license is treated as voluntary transfer of an LLP license (§ 679.4(k)(7)(vii)).

- Fishing privileges of AFA replaced vessels. The replaced vessel is the AFA vessel that has left the AFA fishery and is replaced by another vessel. Under the amended AFA at section 208(g)(5), the replaced vessel is not eligible for a Federal fishery endorsement unless, at some point in the future, the replaced vessel reenters the AFA fishery as a replacement vessel. Thus, the only fishing activity possible for a replaced vessel is reentering the AFA fishery as a replacement vessel.

While the provisions explained above apply generally to rebuilding and replacing AFA catcher/processors, motherships, and catcher vessels, the proposed rule includes specific measures that apply to (1) the rebuilding or replacement of AFA catcher vessels with sideboard exemptions; (2) the replacement of vessels in AFA inshore cooperatives; (3) the status of AFA permits after a vessel is lost; and (4) how the owners of lost catcher AFA vessels may participate in AFA inshore cooperatives. Before examining the provisions in the proposed rule on removing AFA catcher vessels, NMFS will discuss these four special situations regarding rebuilding and replacing AFA vessels.

The Rebuilding or Replacing of AFA Catcher Vessels With Sideboard Exemptions

Under current regulations, AFA catcher vessels are subject to sideboard limitations in the BSAI groundfish fisheries and in the GOA groundfish fisheries, unless an AFA catcher vessel met requirements in § 679.64(b)(2) for an exemption. The regulation provides for an exemption in the BSAI only from BSAI Pacific cod sideboards, not from sideboard limits for any groundfish other than BSAI Pacific cod. The regulation provides for an exemption in the GOA from sideboards for all groundfish species.

In the original AFA, the requirements for initial eligibility for an AFA vessel to be exempt from BSAI Pacific cod sideboard limits were that an AFA catcher vessel (1) was under 125 feet LOA; (2) harvested a relatively small amount of BSAI pollock between 1995 and 1997 (5,100 metric tons); and (3) made a fairly high number of landings of BSAI Pacific cod (30 or more) in that same time period (§ 679.4(l)(3)(ii)(*1*)).

The requirements for initial eligibility for an AFA vessel to be exempt from GOA groundfish sideboard limits were that an AFA catcher vessel (1) was under 125 feet LOA; (2) harvested a relatively small amount of BSAI pollock between 1995 and 1997 (5,100 metric tons); and (3) made a fairly high number of landings of GOA groundfish (40 or more) in that same time period (§ 679.4(l)(3)(ii)(*2*)).

Ten AFA catcher vessels met the requirements for an exemption from BSAI Pacific cod sideboard limits and 16 AFA catcher vessels met the requirements for an exemption from GOA groundfish sideboard limits (Analysis, Section 1.9.1). The regulations also exempt from BSAI Pacific cod sideboard limits a category of AFA catcher vessels regardless of the length of the vessel; namely, AFA catcher vessels that deliver to motherships are exempt from BSAI Pacific cod sideboard closures after March 1 of the fishing year (§ 679.64(b)(2)(i)(B)).

Under the proposed rule at § 679.4(l)(7), the owner of an AFA catcher vessel after rebuilding or replacement would be eligible to participate in the same manner as the vessel before rebuilding or replacement. This means that the owner of an AFA catcher vessel that is exempt from sideboard limits may rebuild or replace the AFA catcher vessel and maintain the exemption from sideboard limits, even if the rebuilt or replacement vessel exceeds the initial eligibility criterion that the vessel be less than 125 feet LOA. This aspect in the proposed rule—the continuation of sideboard exemptions for AFA replacement and rebuilt vessels—implements the language of the amended AFA; was part of Alternative 2, the Council's preferred alternative; and furthers the purpose of the amended AFA.

First, in the amended AFA, section 208(g)(1)(A) states that the expanded privilege for rebuilding and replacing AFA vessels is ''[n]otwithstanding any limitation to the contrary on replacing, rebuilding, or lengthening vessels or transferring permits or licenses to a replacement vessel contained in sections 679.2 and 679.4.'' The requirements for initial eligibility for a sideboard exemption are in § 679.4, which supports the conclusion that an AFA vessel owner should be able to replace, rebuild, or lengthen without being subject to this limitation.

The amended AFA in section 208(g)(1)(B) states that the rebuilt or replacement vessel ''shall be eligible to operate in the same manner and subject to the same restrictions and limitations'' as the vessel before rebuilding or the vessel before replacement. The amended AFA states in section 208(g)(1)(C) that ''[e]ach fishing permit and license held by the owner of the vessel or vessels to be rebuilt or replaced . . . shall be transferred to the rebuilt or replacement vessel or its owner, as necessary to permit such rebuilt or replacement vessel to operate in the same manner as the vessel prior to the rebuilding or the vessel it replaced, respectively.'' Under the amended AFA and this proposed rule, an AFA rebuilt or replacement catcher vessel would maintain an exemption from sideboard closures so as to allow the vessel ''to operate in the same manner'' as the vessel did prior to rebuilding or replacement, notwithstanding the limitation in § 679.4 that an AFA vessel must be less than 125 feet LOA to have an exemption from sideboards.

Second, this provision in the proposed rule—continuation of sideboard exemptions for AFA rebuilt or replacement vessels—was part of Alternative 2, the Council's preferred alternative. Under Alternative 2, as explained in the Analysis, an AFA rebuilt or replacement vessel would have sideboard exemptions if the vessel before rebuilding, or if the vessel that was being replaced, had exemptions (Analysis, Executive Summary at page ix).

Finally, the continuation of sideboard exemptions for AFA rebuilt or replacement vessels furthers the primary purpose of the AFA amendments, which is to allow the owners of AFA vessels to rebuild and replace AFA vessels in accord with their determination that the costs of rebuilding and replacing are worth the benefits. The proposed rule would allow the owner of an AFA catcher vessel that is exempt from AFA sideboards to determine whether to rebuild or replace the vessel based on the costs and benefits of rebuilding and replacing. The proposed rule would not make the owners of AFA sideboard-exempt vessels choose between rebuilding/replacing their vessels andcontinuing to operate with an exemption from sideboard limits.

However, with respect to AFA vessels that are exempt from GOA groundfish sideboard limits, the amended AFA and this proposed rule would preserve the requirement that an AFA vessel may not fish for groundfish in any area in the GOA if the AFA vessel exceeds the MLOA on the vessel's LLP license endorsed for the GOA. This is a very significant constraint on the length of AFA vessels that may operate in the GOA. Although 16 AFA vessels are exempt from sideboard limitations in the GOA, there is only one LLP groundfish license with a Central Gulf area endorsement for a trawl catcher vessel that exceeds 125 feet LOA and that vessel may not exceed 149 feet LOA. There are no LLP groundfish licenses with a Western Gulf area endorsement for a trawl catcher vessel that exceeds 125 feet LOA (Analysis, Table 1–51). Thus, under the proposed rule, only one AFA catcher vessel could exceed 125 feet LOA and operate in the GOA with an exemption from AFA sideboard limits, and that vessel could not be longer than 149 feet LOA.

The Replacement of Catcher Vessels in AFA Inshore Cooperatives

NMFS issues AFA inshore cooperative fishing permits annually to inshore cooperatives. The AFA inshore cooperative fishing permit displays the amount of pollock the inshore cooperative is authorized to harvest for the upcoming fishing year. The permit displays this amount as a percentage of the Bering Sea pollock allocation. NMFS determines this amount by adding together the pollock that each catcher vessel member of the cooperative may harvest. Under the proposed rule, when the owner of a catcher vessel that is a member of an inshore cooperative replaces that vessel, the replacement vessel would be eligible to join the same inshore cooperative of which the replaced vessel was a member. NMFS would transfer the catch history of the replaced vessel to the replacement vessel.

The proposed rule would not change the current deadline for the annual application for an inshore cooperative permit. NMFS still must receive the inshore cooperative application for the upcoming fishing year by December 1 of the prior year. The cooperative application must still list all vessels that are members of the cooperative. And a cooperative will continue to be prohibited from adding or subtracting a vessel for the upcoming fishing year after December 1 of the prior year (§ 679.4(l)(6)(iv), § 679.4(l)(6)(v)). The purpose of the December 1 deadline is to allow NMFS to calculate the allocations for the upcoming year for each cooperative and for the open access sector, if any vessels are in open access.

The December 1 deadline would not apply to applications to replace or remove vessels pursuant to the replacement/removal procedure in this proposed rule. A vessel owner may apply to do that at any time. The replacement or removal of a vessel in an inshore cooperative would not interfere with NMFS' annual calculations for the inshore sector. If NMFS approves the replacement of one vessel that is a member of an inshore cooperative with another vessel, NMFS would not have to change the pollock allocations to the cooperatives. Similarly, if NMFS approves removal of a vessel from an AFA inshore cooperative and assigns the catch history of the removed vessel to one or more vessels in the same cooperative, NMFS would not have to change the allocations to the cooperatives.

The Status of AFA Permits After a Vessel Is Lost

The proposed rule addresses the situation of owners of AFA vessels who experience a total or constructive loss of their vessel. The amended AFA completely revised section 208(g) of the original AFA, which had allowed the owner of AFA vessel to replace the vessel only if it was lost. Section 208(g) of the amended AFA allows the owner of an AFA vessel to replace or rebuild the vessel at any time to improve safety or efficiency.

Under section 208(g) of the original AFA, the owner of an AFA vessel had 36 months from the end of the last year in which the AFA vessel harvested or processed pollock to replace a lost AFA vessel. The original AFA was silent as to the privileges of the owner of a lost AFA vessel during that period and silent as to the privileges of the owner of the lost AFA vessel after that period had lapsed if the owner did not replace the AFA vessel during the allotted time.

The amended AFA also did not explicitly address what happens to the AFA fishing privileges of a lost vessel between the time that the owner loses the vessel and the owner replaces the vessel. To implement the amended AFA, and to provide clarity to the public, the proposed rule specifies the status of an AFA permit in the event of a total or constructive loss of an AFA vessel. NMFS specifically welcomes comment on this provision.

NMFS examined three options. The first option would provide that in the event of a total or constructive loss of an AFA vessel, the AFA permit that designates the lost vessel would immediately become invalid and the owner of the lost AFA vessel would have no AFA fishing privileges until the owner replaces or removes the lost vessel under the replacement/removal procedures in the proposed rule. This approach would pressure the owner of the lost AFA vessel to immediately replace or remove the lost vessel.

The second option would provide that in the event of a total or constructive loss of an AFA vessel, the AFA permit would remain valid until the AFA permit holder designated a replacement vessel. This option would have no mechanism that required the AFA permit holder to designate a replacement vessel and would change the AFA permit from a permit tied to a specific vessel to a permit that was not tied to a vessel. NMFS believes the amended AFA was not meant to fundamentally change the nature of the AFA permit in this way.

The third option would provide that in the event of total or constructive loss of an AFA vessel, the AFA permit would remain valid for a reasonable, but not unlimited, period of time to allow the owner of the lost AFA vessel to continue to receive privileges under the AFA without immediately having to designate a replacement vessel. The proposed rule would implement this

approach. NMFS recognizes that, after a vessel owner incurs the loss of a vessel, it takes time to decide whether and how to replace the vessel. It takes time, sometimes a considerable amount, to collect payment under an insurance policy. It takes time to arrange financing for a replacement vessel. NMFS determined that the proposed rule should provide the vessel owner with a reasonable period of time to take these steps in the wake of an event such as a complete vessel loss.

NMFS determined that a reasonable period of time for the vessel owner to replace a lost vessel or, in the case of an AFA catcher vessel in an inshore cooperative, to remove a lost vessel, is the same period of time that was in the original AFA: the time period starting on the date of the vessel loss and ending on December 31 of the year that is 3 years (36 months) after the year in which the vessel was lost (section 208(g)(3) of the original AFA). It is easier to understand by example. Under the proposed rule at § 679.4(l)(ii), if a vessel sinks on February 15, 2016, the AFA permit on the lost vessel would be valid until December 31, 2019, unless the vessel owner has been issued an AFA permit on a replacement vessel before December 31, 2019, or the vessel owner has removed the lost vessel before that date. For ease of reference, this preamble refers to this time period as a ''3-year period,'' although technically it is a ''3-year plus time period'' because the AFA permit remains valid until December 31 of the year in which the vessel was lost and then 3 more years after that.

NMFS believes that a 3-year period would provide a vessel owner with adequate time to decide whether to replace or remove a lost vessel and to apply to take one of those actions. As noted, this 3-year period is the same period of time that the original AFA in section 208(g) gave the owner of an original AFA vessel to replace an AFA vessel. This 3-year period was adequate for the replacement of four AFA vessels that were lost before enactment of the Coast Guard Act.

Under the proposed rule, NMFS would revoke the AFA permit that designated the lost vessel if, before the end of the 3-year period if, during that period, the owner of the AFA vessel replaces the lost vessel with another vessel or removes the lost vessel pursuant to the replacement/removal procedures established by the proposed rule. It would be inconsistent with the AFA to have two AFA permits authorizing two AFA vessels to fish based on the fishing history of the same lost vessel.

If, at the end of the 3-year period, the AFA vessel owner had not replaced or removed the lost AFA vessel, NMFS would suspend the AFA permit that designated that lost vessel and the AFA permit would not be valid. Since NMFS may have to suspend the AFA permit, the proposed rule would require that the owner of an AFA vessel notify NMFS within 120 days after the vessel is lost.

After the permit was suspended, the owner of the lost AFA vessel could still apply to replace or remove the lost vessel that was designated on the AFA permit. But while the permit was suspended, the owner of the lost AFA vessel would not have a valid AFA permit and would have no fishing privileges based on the suspended AFA permit.

For several reasons, NMFS believes it is highly unlikely that any AFA permits would be suspended under this provision. The permits are valuable. The AFA permit holders have operated in a highly regulated fishery since 1998. And since AFA vessels almost always fish as members of cooperatives, the other members of the cooperative and the cooperative manager would have a great interest in making sure a member's AFA permit is not suspended.

The original AFA in section 208(g) recognized two types of vessel loss that allowed the owner of an AFA vessel to replace an AFA vessel: total loss of the AFA vessel or constructive loss of the AFA vessel. The proposed rule also recognizes these two types of vessel loss. The proposed rule would define total loss and constructive loss for purposes of determining the validity of AFA permits and would clarify when the time period for replacing or removing a vessel would begin. The proposed rule would define total loss and constructive loss in § 679.4(l)(1)(ii)(B)(*3*) and § 679.4(l)(7)(v)(D). Total loss would be defined as the complete physical loss of a vessel, such as when a vessel sinks or is otherwise destroyed. Constructive loss would be defined as when the vessel is damaged so that the cost of repairing the vessel exceeds the value of the vessel. The proposed definition of constructive loss for purposes of AFA permits tracks the common definition of constructive loss used in maritime insurance.

The proposed rule would define the date of the total loss of the vessel as the date when the vessel was physically lost. The proposed rule would define the date of the constructive loss of the vessel as the date when the vessel suffered the damage that resulted in the cost of repair exceeding the value of the vessel.

How the Owners of Lost AFA Catcher Vessels May Participate in AFA Inshore Cooperatives

The proposed rule addresses how NMFS would evaluate an application for an inshore cooperative fishing permit if the applicant includes the catch history of a lost catcher vessel. In examining this provision, it is helpful to keep in mind the standard requirements for a vessel to be a member of a particular cooperative. To be a member of an inshore cooperative, a catcher vessel must meet permit requirements and landing requirements (§ 679.4(l)(6)(ii)(D)(*1*) and (*2*)). The permit requirements are general. An AFA catcher vessel must have a valid AFA permit and an LLP groundfish license that authorizes the vessel to engage in trawling for pollock in the Bering Sea (§ 679.4(l)(6)(ii)(D)(*1*)).

The landing requirements are specific to each cooperative. Each cooperative designates a particular AFA inshore processor to which the cooperative members have agreed to deliver at least 90 percent of their pollock catch (§ 679.4(l)(6)(i)(B)). To be a member of a particular cooperative, the catcher vessel must have delivered more pollock to the processor associated with that cooperative than to any other processor during the prior year or, if the vessel is inactive, during the last year that the vessel made pollock deliveries (§ 679.4(l)(6)(ii)(D)(2)). This means that if a catcher vessel wishes to switch to a new cooperative, the catcher vessel must first spend a year in the open access sector and, for that year, deliver more fish to the processor associated with the new cooperative than to any other processor. After that year, the catcher vessel could join the new cooperative.

As described earlier, under the proposed rule, if an AFA vessel is lost, the AFA permit that designated the lost catcher vessel would be valid for up to 3 years from December 31 of the year in which the vessel was lost. As a corollary to that provision, the proposed rule would establish at § 679.4(l)(6)(ii)(D)(*4*) that, if an AFA catcher vessel with an inshore endorsement is lost, the owner of the lost catcher vessel would be qualified to join an inshore cooperative for up to 3 years from December 31 of the year in which the vessel was lost. The AFA permit designating the lost AFA catcher vessel would be revoked earlier if the owner of the lost catcher vessel replaces the lost vessel or removes the lost vessel. As explained above, if an AFA catcher vessel owner had not replaced or removed the lost vessel by the end of the 3-year period,

the AFA permit that designated the lost vessel would be suspended. While the AFA permit was suspended, the owner of the lost catcher vessel would be unable to be a member of an inshore cooperative because the owner of the lost vessel would not have a valid AFA permit.

The proposed rule would establish which inshore cooperative that the owner of a lost AFA catcher vessel may join during this 3-year period. The proposed rule would do this by adding a provision to the inshore cooperative permit regulation at § 679.4(l)(6)(ii)(D)(*4*). If the catcher vessel was lost during a year when the owner of the lost vessel was a member of an inshore cooperative, the owner of the lost AFA vessel could join that inshore cooperative for the 3-year period while the AFA permit designating the lost vessel remained valid.

In the unlikely event that a catcher vessel is lost during a year when the catcher vessel was not a member of an inshore cooperative, but the vessel had made deliveries to an AFA inshore processor during that year before the vessel was lost, the owner of the lost vessel would be allowed to join the inshore cooperative that is associated with the processor to which the vessel delivered more pollock than any other processor during that year.

In both these situations—when the lost catcher vessel was a member of a cooperative and when the lost catcher vessel was in the open access sector but had made deliveries to a processor associated with a cooperative—the proposed rule would not allow the owner of the lost vessel to join a different cooperative. This limitation is in keeping with the AFA cooperative structure and the landing requirements to be a member of a cooperative (§ 679.4(l)(6)(ii)(D)(*2*)). The owner chose that cooperative for the lost vessel's most recent year of participation. Further, the owner of the lost vessel could not meet the requirements to become a member of a different cooperative; namely after the catcher vessel sank, the vessel could not have delivered pollock to an AFA inshore processor associated with a different cooperative.

In the very unlikely event that a catcher vessel is lost during a year when the vessel was not designated on an inshore cooperative permit, and before the vessel made any pollock deliveries, the owner of the lost vessel would be permitted to join any inshore cooperative while the AFA permit designating the lost vessel was valid.

NMFS notes that it is rare that vessels are lost. From 1998 to 2010, NMFS is aware of only four AFA vessels that were lost. And it is very rare that an inshore catcher vessel is not a member of an inshore cooperative. As noted earlier, since 2004, only two inshore vessels have not fished as a member of a cooperative and that was only for one year (2010). Thus, even though the proposed rule addresses the possibility that a catcher vessel would be lost, and that the lost catcher vessel would not be a member of a cooperative, it is quite unlikely this will occur. If an inshore catcher vessel is lost, in all likelihood, it would be completely straightforward what cooperative the owner of the lost catcher vessel may join during the 3-year period when the permit may remain valid. It would be the cooperative of which the lost catcher vessel was a member.

Removing an AFA Catcher Vessel From the AFA Fishery

The proposed rule at § 679.4(l)(7)(iii) would allow the owner of an AFA catcher vessel that is a member of an inshore cooperative to remove that vessel from the AFA fishery and assign the Bering Sea pollock catch history of the removed vessel to one or more catcher vessels within the cooperative subject to four conditions that NMFS would administer. Each of these conditions is required by section 210(b) of the amended AFA.

First, under the proposed rule at § 679.4(l)(7)(iii)(B), the owner of the AFA catcher vessel that is being removed would be required to direct NMFS to assign the catch history of the removed catcher vessel to one or more AFA catcher vessels that are members of the inshore cooperative to which the removed vessel belonged as of the date that the vessel owner submitted an application for removal. If the owner of the AFA catcher vessel directs NMFS to assign the catch history of the removed vessel to more than one vessel, the owner would be required to specify the percentage of catch history that would be assigned to each vessel. The proposed regulation would not allow the catch history of the removed vessel to be free-floating, or unassigned. The catch history must be assigned to one or more vessels in the cooperative to which the removed vessel belonged. The approval by NMFS of removing a catcher vessel and the assignment by NMFS of the catch history to another vessel or vessels would occur at the same time.

Second, except for assigning the inshore pollock catch history, NMFS would permanently extinguish all other claims relating to the catch history of the removed vessel. The proposed rule at § 679.4(l)(7)(C) includes this provision. Specifically, under the proposed rule, if an AFA catcher vessel is exempt from an AFA sideboard limitation, and that vessel is removed from the AFA fishery, NMFS would permanently extinguish that sideboard exemption and would not assign the exemption to any other vessel or vessels in the inshore cooperative.

Third, under the proposed rule at § 679.4(l)(7)(iii)(D), the vessel or vessels that are assigned the catch history of the removed vessel—the receiving vessel or vessels—could not themselves be removed from the cooperative for one year from the date on which the receiving vessel or vessels were assigned the catch history of the removed vessel. For example, under the proposed rule, if NMFS approved the assignment of catch history of a removed vessel to a receiving vessel on July 1, 2016, the receiving vessel could not be removed from the cooperative until July 1, 2017.

Fourth, under the proposed rule at § 679.4(l)(7)(iv), a vessel that is removed would be permanently ineligible to receive any permits to operate in the Exclusive Economic Zone (EEZ) off Alaska unless, after being removed, the removed vessel reenters the AFA fishery as a replacement vessel for another vessel. This is based on section 210(b)(7)(B), which states that removal of a catcher vessel from an inshore cooperative extinguishes ''any claim (including relating to catch history) associated with such vessel that could qualify any owner of such vessel for any permit to participate in the exclusive economic zone of the United States.'' While the proposed rule would prohibit participation by a removed vessel in the EEZ off Alaska, it is important to note that section 210(b)(7)(B) prohibits participation by a removed vessel in the entire United States EEZ.

Application Procedures

NMFS has created one form that would be used by the owners of AFA vessels that rebuild, replace, or remove their AFA vessels: ''American Fisheries Act (AFA) Permit: Rebuilt, Replaced, or Removed Vessel Application.'' The application and instructions would be published on the NMFS Alaska Region Web site at *www.alaskafisheries.noaa.gov* upon the effective date of a final rule.

After NMFS receives a complete application, NMFS would take the action requested by the applicant if the applicant met the requirements for NMFS to take the action. If the

application is a notification to NMFS of an AFA rebuilt vessel, NMFS would acknowledge the notification. The AFA vessel would be designated on an LLP license. NMFS would reissue to the AFA rebuilt vessel an LLP groundfish license with an exemption from the MLOA restriction when the AFA rebuilt vessel is used to fish for groundfish in the BSAI pursuant to that LLP license.

If the applicant seeks to replace an AFA vessel, NMFS would issue a new AFA permit to the replacement vessel, unless the replacement vessel already is designated on an AFA permit. NMFS would revoke the AFA permit on the former, or replaced, AFA vessel. On the application form, the AFA vessel owner would indicate the LLP license on which the AFA replacement vessel would be designated. NMFS would issue to the AFA replacement vessel an LLP groundfish license with an exemption from the MLOA restriction. The exemption would only be valid when the AFA replacement vessel is used to fish for groundfish in the BSAI pursuant to that LLP license. If the applicant seeks to replace an AFA catcher vessel with an inshore endorsement, NMFS would modify the AFA permit of the replacement vessel so that the replacement vessel has the exemptions from sideboard limitations, if any, of the replaced vessel.

If the applicant seeks to remove an AFA catcher vessel with an inshore endorsement, NMFS would assign the pollock catch history of the removed vessel to one or more vessels in the inshore cooperative to which the removed vessel belonged, in accord with the application of the owner of the removed vessel. NMFS would notify the applicant that the AFA permit designating the removed catcher vessel was revoked and that, except for the reassigned pollock history, NMFS had extinguished all claims related to the catch history of the removed vessel, including any claims to exemptions from sideboard limitations.

If NMFS believes that the application is deficient, NMFS would notify the applicant and give the applicant one 30-day period to remedy the deficiencies in the application. After the 30-day period, NMFS would review the application and any information submitted within the 30-day period. NMFS would either grant the application or deny the application by issuing an Initial Administrative Determination (IAD), which would explain the basis for the denial.

Appeal Procedures

Under the proposed rule at § 679.4(l)(8)(iii), an applicant would be able to appeal the denial of an application pursuant to the appeal procedures at 15 CFR part 906. NMFS has established a National Appeals Office (NAO) located at NMFS Headquarters in Silver Spring, Maryland. In 2014, NMFS adopted rules of procedure for NAO appeals in 15 CFR part 906. (Final Rule, 79 FR 7056 (Feb. 6, 2014)). The appeal procedures in 15 CFR part 906 are mandatory for appeals in limited access privilege programs (LAPPs) under section 303A of the Magnuson-Stevens Act. 15 CFR 906.1(b). Section 303A applies only to limited access privilege programs that were adopted after January 12, 2007, the date of enactment of the Magnuson-Stevens Fishery Conservation and Management Reauthorization Act of 2006. 16 U.S.C. 1853a. The AFA was adopted on October 21, 1998. Therefore, AFA appeals are not required to be heard under the procedural rules at 15 CFR part 906.

NMFS may, however, request that NAO decide appeals in programs where NAO does not have mandatory jurisdiction. 15 CFR 906.1(d). In the proposed rule, NMFS proposes to use NAO for appeals of initial administrative determinations issued under this rule and to adopt 15 CFR part 906 as the procedural rules for AFA appeals.

In the past, NMFS Alaska Region had its own appeals office and its own procedural rules for appeal in 50 CFR 679.43. NMFS Alaska Region no longer has its own appeals office and therefore is opting to use the NAO and the procedural rules for the NAO.

In developing this proposed rule, NMFS identified an error in the definition of mothership in 50 CFR 679.2. The current regulation states: ''AFA mothership means a mothership permitted to process BS pollock under § 679.4(l)(5).'' Section 679.4(l)(5) is ''AFA inshore processor permits.'' Section 679.4(l)(4) is ''AFA mothership permits.'' NMFS therefore proposes to change the definition of mothership in § 679.2 to state: ''AFA mothership means a mothership permitted to process BS pollock under § 679.4(l)(4).''

Classification

Pursuant to section 304(b)(1)(A) and 305(d) of the Magnuson-Stevens Act, the NMFS Assistant Administrator has determined that this proposed rule is consistent with the BSAI FMP, other provisions of the Magnuson-Stevens Act, and other applicable law, subject to further consideration of comments received during the public comment period.

The proposed rule has been determined to be not significant for purposes of Executive Order 12866.

A Regulatory Impact Review/Initial Regulatory Flexibility Analysis was prepared. An Initial Regulatory Flexibility Analysis (IRFA) was prepared as required in section 603 of the Regulatory Flexibility Act (RFA). On June 20, 2013, the Small Business Administration issued a final rule revising the small business size standards for several industries effective July 22, 2013 (78 FR 37398, June 20, 2013). The rule increased the size standard for Finfish Fishing from $4.0 to 19.0 million, Shellfish Fishing from $4.0 to 5.0 million, and Other Marine Fishing from $4.0 to 7.0 million. Id. at 37400 (Table 1). The new size standards were used to prepare the IRFA for this action.

The IRFA describes the economic impact this proposed rule, if adopted, would have on small entities. A description of the action, why it is being considered, and the legal basis for this action are contained under the heading ''Need for Action'' in the preamble and in the **SUMMARY** section of the preamble. A summary of the Analysis follows. A copy of the complete Analysis is available from NMFS (see **ADDRESSES**).

Number and Description of Small Entities Regulated by the Proposed Action

This action would regulate the owners of vessels that are designated on AFA permits; these vessels are catcher vessels, catcher/processor vessels, and motherships. In 2013, 105 catcher vessels, 21 catcher/processors, and 3 motherships were designated on AFA permits (Analysis, Section 2.4). In assessing whether an entity is small, the RFA requires NMFS to consider affiliations between entities.

With respect to AFA catcher/processors, the IRFA states: ''All AFA catcher/processors are affiliated through membership in the Pollock Conservation Cooperative; the members of this cooperative had estimated 2012 gross revenues from pollock alone in excess of $500 million. Thus these are large entities.'' (Analysis, Section 2.4, footnote omitted).

With respect to catcher vessels, the IRFA states: ''All AFA catcher vessels are members of one of eight cooperatives delivering pollock to inshore processing plants, to motherships, or to catcher/processors. The cooperative of catcher vessels delivering to catcher/processors was closely affiliated with the catcher/processor cooperative, and thus the member entities are large. The seven cooperatives delivering to processing

plants or motherships had gross revenues from pollock alone in excess of $19 million, and/or were affiliated with processing operations that themselves met the large entity threshold of 500 employees for entities of that type, and/or were affiliated with processors who did.'' (Analysis, Section 2.4).

With respect to AFA motherships, the IRFA states: ''Three motherships accept deliveries of pollock from catcher vessels. While these vessels are authorized to join the cooperative of catcher vessels making such deliveries, they have not recently chosen to do so. However, each of these motherships is believed to be a large entity, based on corporate affiliations with other large processing firms.'' (Analysis, Section 2.4).

Thus, the IRFA concluded that all of the entities regulated by this action are ''large'' entities for the purpose of the RFA. If that is so, NMFS need not have prepared an IRFA for this proposed rule because an IRFA is necessary only to evaluate the impact of a proposed rule on small entities. NMFS prepared an IRFA, however, because the IRFA acknowledged that the data on ownership and affiliation of AFA entities was limited.

Recordkeeping and Reporting Requirements

This action imposes one additional reporting requirement on the owner of an AFA rebuilt vessel. If the owner of an AFA vessel rebuilds an AFA vessel, the owner shall submit the documentation for the rebuilt vessel to NMFS within 30 days of the issuance of the documentation.

Apart from this requirement, the owners of AFA rebuilt vessels would be subject to the same recordkeeping and reporting requirements after rebuilding as before rebuilding. Similarly, the owners of AFA replacement vessels would be subject to the same recordkeeping and reporting requirements that applied to the replaced, or former, AFA vessel. If a vessel is removed, the owners of the AFA vessels that are assigned the catch history of the removed vessel would be subject to the same recordkeeping and reporting requirements after they are assigned the catch history of the removed vessel as before they were assigned the catch history of the removed vessel.

NMFS has created an application form for the owner of an AFA vessel who wishes to take any of the actions allowed by this rule. The application form allows the owner of an AFA vessel to notify NMFS of rebuilding, to request to replace an AFA vessel, or to remove an AFA vessel.

Duplicate, Overlapping, or Conflicting Federal Rules

This proposed rule is necessary because existing rules conflict with the AFA amendments in the Coast Guard Act. Apart from that conflict, NMFS has not identified any duplication, overlap, or conflict between this proposed action and existing Federal rules.

Description of Significant Alternatives That Minimize Adverse Impacts on Small Entities

Section 603 of the RFA requires that NMFS should describe any significant alternatives to the proposed action that would accomplish the stated objectives of applicable statutes and would minimize any significant adverse economic impacts on small entities. Although the IRFA concluded that this action did not directly regulate any small entities, the Council and NMFS assumed, for the purpose of the IRFA, that the directly regulated entities were small entities and considered the potential effects on the directly regulated entities.

The Council considered Alternative 1; Alternative 2; and Alternatives 2.1, 2.2, 2.3, and 2.4. Alternative 1 was no action. The Council did not adopt Alternative 1 because it did not conform regulations and the BSAI FMP to a statute adopted by Congress, namely the AFA amendments in the Coast Guard Act. Alternative 1 continued the stringent restrictions in current regulation on the ability of the owners of AFA vessels to upgrade their vessels through rebuilding or replacing the vessels. Alternative 1 continued the prohibition in current regulation on the owners of AFA catcher vessels from removing their vessels and assigning the catch history of their vessels to other vessels in their cooperatives. Alternative 1 completely contradicted the objectives of the amended AFA.

Under Alternative 2, ''the status quo'' alternative, fishery management plans and existing regulations would be changed to conform to the AFA amendments, as NMFS interprets the AFA amendments. The Council and NMFS concluded that the BSAI FMP was inconsistent with the AFA amendments. The Council and NMFS therefore proposed amending the BSAI FMP with Amendment 106 to the BSAI FMP. The Council and NMFS concluded that the GOA FMP was consistent with the amended AFA and therefore proposed no change to the GOA FMP.

Alternative 2 would change the BSAI FMP and implementing regulations to allow the owners of AFA vessels to participate in the BSAI with a rebuilt or replacement vessel without limit on the length, tonnage, or horsepower of the rebuilt or replacement vessel. Alternative 2 continues all the restrictions currently in place on participation by AFA vessels in the GOA, including the requirement that an AFA vessel may not participate in the GOA unless the vessel has an LLP license and the vessel does not exceed the MLOA on that license. The Council selected Alternative 2 as its preferred alternative.

Alternatives 2.1, 2.2, 2.3, and 2.4 would have imposed additional restrictions on participation by AFA rebuilt and replacement vessels in the GOA, in addition to restrictions in current regulations (Analysis, Executive Summary). Alternative 2.1 stated that an AFA rebuilt and replacement vessel that is subject to sideboards could not participate in the GOA if the vessel exceeded the most restrictive MLOA on any GOA LLP license assigned to the vessel at the time that the vessel owner applied to NMFS to replace or rebuild the AFA vessel. Alternative 2.2 stated that an AFA rebuilt or replacement vessel that is subject to sideboards could not participate in the GOA if the vessel exceeded the most restrictive MLOA on any GOA LLP license assigned to the vessel on October 15, 2010, the date of passage of the Coast Guard Act. Alternative 2.3 stated that an AFA rebuilt or replacement vessel that is subject to sideboards could not participate in the GOA if the AFA rebuilt or replacement vessel was greater than 10 percent over the length, tonnage, or horsepower of the vessel on October 15, 2010. Alternative 2.4 stated that an AFA rebuilt or replacement vessel that is not subject to sideboards could not exceed the MLOA on any GOA LLP license assigned to the vessel on October 15, 2010.

Section 208(g)(2) of the amended AFA expressly gave the Council the authority to adopt conservation and management measures to ensure that the AFA amendments did not diminish the effectiveness of the fishery management plans for the Bering Sea or GOA. Alternatives 2.1, 2.2, 2.3, and 2.4 were the alternatives analyzed by the Council under section 208(g)(2).

As to which alternative achieves the objectives of the amended AFA, Alternatives 2, 2.1, 2.2, 2.3, and 2.4 all expand the ability of the owners of AFA vessels to rebuild or replace AFA vessels over the original AFA. However, Alternative 2 best achieves the objective

of the AFA amendments because the objective of the AFA amendments was to impose additional restrictions on the rebuilding and replacement of AFA vessels only if the additional restrictions were necessary to protect the fishery management plans of the BSAI or GOA. The Council did not recommend additional restrictions in either the BSAI or GOA.

As to which alternative minimizes the adverse economic impact on small entities, the Analysis concluded that no AFA vessels are small entities. Therefore none of the alternatives directly regulates small entities and none of the alternatives minimize the adverse economic impacts on small entities.

But assuming for the purposes of analysis that the owners of AFA vessels are small entities, Alternative 2 is the alternative that minimizes the potential adverse economic impacts on the owners of AFA vessels. The reason is that Alternative 2 would allow the owners of AFA vessels to rebuild and replace their vessels without any restrictions on their ability to rebuild and replace vessels beyond the restrictions required by the AFA amendments. Alternative 2 allows the owners of AFA vessels to rebuild and replace their vessels if the vessel owners conclude that the improved safety and efficiency of the rebuilt or replacement vessel warrants the cost of rebuilding or replacing the vessel.

Collection-of-Information Requirements

This proposed rule contains collection-of-information requirements subject to review and approval by the Office of Management and Budget (OMB) under the Paperwork Reduction Act (PRA). NMFS has submitted these requirements to OMB for approval under OMB Control Number 0648–0393. The public reporting burden for ''American Fisheries Act (AFA) Permit: Rebuilt, Replacement, or Removed Vessel Application'' is estimated to average 2 hours per response. This estimate includes the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection-of-information.

Public comment is sought regarding whether this proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; the accuracy of the burden estimate; ways to enhance the quality, utility, and clarity of the information to be collected; and ways to minimize the burden of the collection of information, including through the use of automated collection techniques or other forms of information technology. Send comments on these or any other aspects of the collection of information to NMFS at the **ADDRESSES** above, and by email to *OIRA_Submission@omb.eop.gov,* or fax to 202–395–7285.

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. All currently approved NOAA collections of information may be viewed at: *http://www.cio.noaa.gov/services_programs/prasubs.html.*

List of Subjects in 50 CFR Part 679

Alaska, Fisheries, Reporting and recordkeeping requirements.

Dated: June 10, 2014.

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 679 is proposed to be amended as follows:

PART 679—FISHERIES OF THE EXCLUSIVE ECONOMIC ZONE OFF ALASKA

■ 1. The authority citation for 50 CFR part 679 is revised to read as follows:

Authority: 16 U.S.C. 773 *et seq.;* 1801 *et seq.;* 3631 *et seq.;* Pub. L. 108–447; Pub. L. 111–281.

* * * * *

■ 2. In § 679.2,

■ a. Revise the definition of ''AFA mothership;'' and

■ b. Add definitions for ''AFA rebuilt vessel,'' ''AFA replacement vessel,'' and ''AFA vessel'' in alphabetical order, and add paragraph (2)(vi) to the definition of ''Maximum LOA (MLOA)'' to read as follows:

§ 679.2 Definitions.

* * * * *

AFA mothership means a mothership permitted to process BS pollock under § 679.4(l)(4).

* * * * *

AFA rebuilt vessel means an AFA vessel that was rebuilt after October 15, 2010.

AFA replacement vessel means a vessel that NMFS designated on an AFA permit pursuant to § 679.4(l)(7) after October 15, 2010.

AFA vessel means a vessel that is designated on an AFA catcher vessel permit, an AFA catcher/processor permit, or an AFA mothership permit, and is thereby authorized to participate in the Bering Sea directed pollock fishery.

* * * * *

Maximum LOA (MLOA) means: * * *

(2) * * *

(vi) An AFA vessel is exempt from the MLOA on an LLP license with a Bering Sea area endorsement or an Aleutian Islands area endorsement when the vessel is used in the BSAI to harvest or process license limitation groundfish and the LLP license specifies an exemption from the MLOA restriction for the AFA vessel.

* * * * *

3. In § 679.4,

a. Remove paragraphs (a)(1)(iii)(F), (l)(4) introductory text, and (l)(8)(iv);

b. Redesignate paragraphs (l)(2)(iii) as (l)(2)(iv) and (l)(8)(v) as (l)(8)(iv);

c. Revise paragraphs (k)(1)(i), (k)(3)(i)(A), (l)(1)(ii)(B), (l)(3)(i)(A)(*2*), (l)(3)(i)(B)(*2*), (l)(3)(i)(C)(*2*)(*ii*), (l)(4)(i), (l)(6)(ii)(C)(*3*), (l)(6)(ii)(D) introductory text, (l)(7), (l)(8)(i), (l)(8)(ii), (l)(8)(iii), and (o)(4)(i)(D); and

d. Add paragraphs (k)(3)(i)(E), (l)(2)(iii), (l)(3)(i)(A)(*3*), (l)(3)(i)(B)(*3*), (l)(3)(i)(C)(*3*), (l)(3)(ii)(E)(*3*), (1)(6)(ii)(D)(*3*), and (l)(6)(ii)(D)(*4)* to read as follows:

§ 679.4 Permits.

* * * * *

(k) * * *

(1) * * *

(i) In addition to the permit and licensing requirements of this part, and except as provided in paragraph (k)(2) of this section, each vessel within the GOA or the BSAI must have an LLP groundfish license on board at all times it is engaged in fishing activities defined in § 679.2 as directed fishing for license limitation groundfish. This groundfish license, issued by NMFS to a qualified person, authorizes a license holder to deploy a vessel to conduct directed fishing for license limitation groundfish only in accordance with the specific area and species endorsements, the vessel and gear designations, the MLOA specified on the license, and any exemption from the MLOA specified on the license.

* * * * *

(3) * * *

(i) * * *

(A) *General.* A license may be used only on a vessel designated on the license, a vessel that complies with the vessel designation and gear designation specified on the license, and a vessel that has an LOA less than or equal to the MLOA specified on the license, unless

the license specifies that the vessel is exempt from the MLOA on the license.

* * * * *

(E) *Exemption from MLOA on an LLP license with a Bering Sea area endorsement or an Aleutian Islands area endorsement for AFA rebuilt or AFA replacement vessels.* An AFA rebuilt vessel or an AFA replacement vessel may exceed the MLOA on an LLP groundfish license with a Bering Sea area endorsement or an Aleutian Islands area endorsement when the vessel is conducting directed fishing for groundfish in the BSAI pursuant to that LLP groundfish license and when the exemption is specified on the LLP license.

* * * * *

(l) * * *

(1) * * *

(ii) * * *

(B) *Duration of final AFA permits.* (*1*) Except as provided in paragraphs (l)(1)(ii)(B)(*2*), (l)(1)(ii)(B)(*3*), (l)(5)(v)(B)(*3*), and (l)(6)(iii) of this section, AFA vessel and processor permits issued under this paragraph (l) are valid indefinitely unless the permit is suspended or revoked.

(*2*) An AFA vessel permit is revoked when the vessel designated on the permit is replaced or removed under paragraph (l)(7) of this section.

(*3*) In the event of a total loss or constructive loss of an AFA vessel,

(*i*) The AFA vessel permit that designates the lost AFA vessel will be valid from the date of the vessel loss up to 3 years from December 31 of the year in which the vessel was lost and will be suspended after that date, unless the AFA vessel permit for the lost vessel was revoked before that date because the lost vessel was replaced or removed under paragraph (l)(7) of this section. For example, if a vessel sinks on February 15, 2016, the AFA permit on the vessel will be valid until December 31, 2019, unless the owner of the vessel replaces or removes the vessel before December 31, 2019; after December 31, 2019, the AFA permit on the lost vessel will be suspended until the AFA vessel owner replaces or removes the lost vessel;

(*ii*) The owner of the lost AFA vessel must notify NMFS in writing of the vessel loss within 120 days of the date of the total loss or constructive loss of the vessel;

(*iii*) For purposes of paragraph (l)(1)(ii)(B)(*3*) of this section, an AFA lost vessel is a vessel that has been subject to a total loss or a constructive loss; a total loss means that the vessel is physically lost such as from sinking or a fire; a constructive loss means that the vessel suffered damage so that the cost of repairing the vessel exceeded the value of the vessel; the date of the total loss of a vessel is the date on which the physical loss occurred; the date of the constructive loss of a vessel is the date on which the damage to the vessel occurred.

* * * * *

(2) * * *

(iii) *AFA replacement vessels.* (A) NMFS will issue a listed AFA catcher/processor permit to the owner of a catcher/processor that is a replacement vessel for a vessel that was designated on a listed AFA catcher/processor permit.

(B) NMFS will issue an unlisted AFA catcher/processor permit to the owner of a catcher/processor that is a replacement vessel for a vessel that was designated on an unlisted AFA catcher/processor permit.

* * * * *

(3) * * *

(i) * * *

(A) * * *

(*2*) Is not listed in paragraph (l)(3)(i)(A)(*1*) of this section and is determined by the Regional Administrator to have delivered at least 250 mt and at least 75 percent of the pollock it harvested in the directed BSAI pollock fishery in 1997 to catcher/processors for processing by the offshore component; or

(*3*) Is an AFA replacement vessel for a vessel that was designated on an AFA catcher vessel permit with a catcher/processor endorsement.

(B) * * *

(*2*) Is not listed in paragraph (l)(3)(i)(B)(*1*) of this section and is determined by the Regional Administrator to have delivered at least 250 mt of pollock for processing by motherships in the offshore component of the BSAI directed pollock fishery in any one of the years 1996 or 1997, or between January 1, 1998, and September 1, 1998, and is not eligible for an endorsement to deliver pollock to catcher/processors under paragraph (l)(3)(i)(A) of this section; or

(*3*) Is an AFA replacement vessel for a vessel that was designated on an AFA catcher vessel permit with a mothership endorsement.

(C) * * *

(*2*) * * *

(*ii*) Is less than 60 ft (18.1 meters) LOA and is determined by the Regional Administrator to have delivered at least 40 mt of pollock harvested in the directed BSAI pollock fishery for processing by the inshore component in any one of the years 1996 or 1997, or between January 1, 1998, and September 1, 1998; or

(*3*) Is an AFA replacement vessel for a vessel that was designated on an AFA catcher vessel permit with an inshore endorsement.

(E) * * *

(*3*) *AFA replacement vessel for a catcher vessel that qualified for an exemption.* A catcher vessel that is a replacement vessel for a vessel that was designated on an AFA catcher vessel permit with an exemption from a groundfish sideboard directed fishing closure will receive an AFA catcher vessel permit with the same exemption as the replaced vessel.

(4) * * *

(i) NMFS will issue to an owner of a mothership an AFA mothership permit if the mothership:

(A) Is one of the following (as listed in paragraphs 208(d)(1) through (3) of the AFA):

EXCELLENCE (USCG documentation number 967502);

GOLDEN ALASKA (USCG documentation number 651041); and

OCEAN PHOENIX (USCG documentation number 296779); or

(B) Is an AFA replacement vessel for a vessel that was designated on an AFA mothership permit.

* * * * *

(6) * * *

(ii) * * *

(C) * * *

(*3*) Each catcher vessel in the cooperative is a qualified catcher vessel and is otherwise eligible to fish for groundfish in the BSAI, except that a lost vessel that retains an AFA permit pursuant to paragraph (l)(1)(ii)(B)(*3*) of this section need not be designated on a Federal Fisheries Permit or an LLP license; has an AFA catcher vessel permit with an inshore endorsement; and has no permit sanctions or other type of sanctions against it that would prevent it from fishing for groundfish in the BSAI.

(D) *Qualified catcher vessels.* For the purpose of paragraph (l)(6)(ii)(C)(*3*) of this section, a catcher vessel is a qualified catcher vessel if the catcher vessel meets the permit and landing requirements in paragraphs (l)(6)(ii)(D)(*1*) and (l)(6)(ii)(D)(*2*) of this section; the catcher vessel is an AFA replacement catcher vessel that meets the requirements in paragraph (l)(6)(ii)(D)(*3*) of this section; or the catcher vessel is an AFA lost catcher vessel that meets the requirements in paragraph (l)(6)(ii)(D)(*4*) of this section.

* * * * *

(*3*) *AFA replacement catcher vessels.* The vessel is an AFA replacement vessel for a catcher vessel that met the permit and landing requirements in

paragraphs (l)(6)(ii)(D)(*1*) and (l)(6)(ii)(D)(*2*) of this section;

(*4*) *AFA lost catcher vessels.* In the event of a total loss or constructive loss of an AFA catcher vessel with an inshore endorsement, the owner of the lost vessel has an AFA catcher vessel permit with an inshore endorsement for the lost vessel that is valid pursuant to paragraph (l)(1)(ii)(B)(*3*) of this section, and the inshore cooperative shows:

(*i*) The vessel was lost during a year when the vessel was designated on an AFA inshore cooperative fishing permit issued to the cooperative submitting the application; or

(*ii*) The vessel was lost during a year when the vessel was not designated on any AFA inshore cooperative fishing permit and when the vessel delivered more pollock to the AFA inshore processor designated by the inshore cooperative under paragraph (l)(6)(ii)(B) of this section than to any other processor; or

(*iii*) The vessel was lost during a year when the vessel was not designated on any AFA inshore cooperative fishing permit and when the vessel had made no deliveries of pollock and the owner of the lost vessel has assigned the catch history of the lost vessel to the inshore cooperative that submits the application.

* * * * *

(7) *AFA rebuilt vessels, AFA replacement vessels, and removal of inshore AFA catcher vessels*—(i) *AFA rebuilt vessels.* (A) To improve vessel safety or to improve operational efficiency, including fuel efficiency, the owner of an AFA vessel may rebuild the vessel. If the owner of an AFA vessel rebuilds the vessel, the owner must notify NMFS within 30 days of the issuance of the vessel documentation for the AFA rebuilt vessel and must provide NMFS with a copy of the vessel documentation for the rebuilt vessel. If the owner of the AFA rebuilt vessel provides NMFS with information demonstrating that the AFA rebuilt vessel is documented with a fishery endorsement issued under 46 U.S.C. 12113, NMFS will acknowledge receipt of the notification and inform the owner that the AFA permit issued to the vessel before rebuilding is valid and can be used on the AFA rebuilt vessel.

(B) Except as provided in paragraph (l)(7)(i)(C) and paragraph (l)(7)(i)(D) of this section, the owner of an AFA rebuilt vessel will be subject to the same requirements that applied to the vessel before rebuilding and will be eligible to use the AFA rebuilt vessel in the same manner as the vessel before rebuilding.

(C) An AFA rebuilt vessel is exempt from the maximum length overall (MLOA) restriction on an LLP groundfish license with a Bering Sea area endorsement or an Aleutian Islands area endorsement when the AFA rebuilt vessel is conducting directed fishing for groundfish in the BSAI pursuant to that LLP groundfish license and the LLP groundfish license specifies the exemption.

(D) If an AFA rebuilt catcher vessel is equal to or greater than 125 ft (38.1 m) LOA, the AFA rebuilt catcher vessel will be subject to the catcher vessel exclusive fishing seasons for pollock in 50 CFR 679.23(i) and will not be exempt from 50 CFR 679.23(i) even if the vessel before rebuilding was less than 125 ft (38.1 m) LOA and was exempt from 50 CFR 679.23(i).

(ii) *AFA replacement vessels.* (A) To improve vessel safety or to improve operational efficiency, including fuel efficiency, the owner of an AFA vessel may replace the AFA vessel with a vessel that is documented with a fishery endorsement issued under 46 U.S.C. 12113.

(B) Upon approval of an application to replace an AFA vessel pursuant to paragraph (l)(7) of this section and except as provided in paragraph (l)(7)(ii)(C), paragraph (l)(7)(ii)(D), and paragraph (l)(7)(E) of this section, the owner of an AFA replacement vessel will be subject to the same requirements that applied to the replaced vessel and will be eligible to use the AFA replacement vessel in the same manner as the replaced vessel. If the AFA replacement vessel is not already designated on an AFA permit, the Regional Administrator will issue an AFA permit to the owner of the AFA replacement vessel. The AFA permit that designated the replaced, or former, AFA vessel will be revoked.

(C) An AFA replacement vessel is exempt from the maximum length overall (MLOA) restriction on an LLP groundfish license with a Bering Sea area endorsement or an Aleutian Islands area endorsement when the AFA replacement vessel is conducting directed fishing for groundfish in the BSAI pursuant to that LLP groundfish license and the LLP groundfish license specifies an exemption from the MLOA restriction for the AFA replacement vessel.

(D) If an AFA replacement catcher vessel is equal to or greater than 125 ft (38.1 m) LOA, the AFA replacement catcher vessel will be subject to the catcher vessel exclusive fishing seasons for pollock in 50 CFR 679.23(i) and will not be exempt from 50 CFR 679.23(i), even if the replaced vessel was less than 125 ft (38.1 m) LOA and was exempt from 50 CFR 679.23(i).

(E) An AFA replacement catcher vessel for an AFA catcher vessel will have the same sideboard exemptions, if any, as the replaced AFA catcher vessel, except that if the AFA replacement vessel was already designated on an AFA permit as exempt from sideboard limits, the AFA replacement vessel will maintain its exemption even if the replaced vessel was not exempt from sideboard limits.

(iii) *Removal of AFA catcher vessel from the directed pollock fishery.* (A) The owner of a catcher vessel that is designated on an AFA catcher vessel permit with an inshore endorsement may remove the catcher vessel from the directed pollock fishery, subject to the requirements in paragraphs (B), (C), (D), and (E) of this paragraph (l)(7)(iii).

(B) The owner of the removed catcher vessel must direct NMFS to assign the non-CDQ inshore pollock catch history in the BSAI of the removed vessel to one or more catcher vessels in the inshore fishery cooperative to which the removed vessel belonged at the time of the application for removal.

(C) Except for the assignment of the pollock catch history of the removed catcher vessel in paragraph (l)(7)(iii)(B) of this section, all claims relating to the catch history of the removed catcher vessel, including any claims to an exemption from AFA sideboard limitations, will be permanently extinguished upon NMFS' approval of the application to remove the catcher vessel and the AFA permit that was held by the owner of the removed catcher vessel will be revoked.

(D) The catcher vessel or vessels that are assigned the catch history of the removed catcher vessel cannot be removed from the fishery cooperative to which the removed catcher vessel belonged for a period of one year from the date that NMFS assigned the catch history of the removed catcher vessel to that vessel or vessels.

(iv) *Replaced vessels and removed vessels.* An AFA vessel that is replaced or removed under paragraph (l)(7) of this section is permanently ineligible to receive any permit to participate in any fishery in the Exclusive Economic Zone off Alaska unless the replaced or removed vessel reenters the directed pollock fishery as a replacement vessel under paragraph (l)(7) of this section.

(v) *Application.* To notify NMFS that the owner of an AFA vessel has rebuilt the AFA vessel, the owner of the AFA vessel must submit a complete application. To replace an AFA vessel with another vessel, NMFS must receive a complete application from the owner of the vessel that is being replaced. To remove an AFA catcher vessel from the

directed pollock fishery, NMFS must receive a complete application from the owner of the vessel that is to be removed. An application must contain the information specified on the application form, with all required fields accurately completed and all required documentation attached. The application must be submitted to NMFS using the methods described on the application. The application referred to in this paragraph is ''American Fisheries Act (AFA) Permit: Rebuilt, Replacement, or Removed Vessel Application.''

(8) * * *

(i) *Initial evaluation.* The Regional Administrator will evaluate an application submitted in accord with paragraph (l) of this section. If the Regional Administrator determines that the applicant meets the requirements for NMFS to take the action requested on the application, NMFS will approve the application. If the Regional Administrator determines that the applicant has submitted claims based on inconsistent information or fails to submit the information specified in the application, the applicant will be provided a single 30-day evidentiary period to submit evidence to establish that the applicant meets the requirements for NMFS to take the requested action. The burden is on the applicant to establish that the applicant meets the criteria in the regulation for NMFS to take the action requested by the applicant.

(ii) *Additional information and evidence.* The Regional Administrator will evaluate the additional information or evidence submitted by the applicant within the 30-day evidentiary period. If the Regional Administrator determines that the additional information or evidence meets the applicant's burden of proof, the application will be approved. However, if the Regional Administrator determines that the applicant did not meet the applicant's burden of proof, the applicant will be notified by an initial administrative determination (IAD) that the application is denied.

(iii) *Initial administrative determinations (IAD).* The Regional Administrator will prepare and send an IAD to the applicant following the expiration of the 30-day evidentiary period if the Regional Administrator determines that the information or evidence provided by the applicant fails to support the applicant's claims and is insufficient to establish that the applicant meets the requirements for an AFA permit or for NMFS to approve the withdrawal of a catcher vessel, or if the additional information, evidence, or revised application is not provided within the time period specified in the letter that notifies the applicant of the applicant's 30-day evidentiary period. The IAD will indicate the deficiencies in the application, including any deficiencies with the information, the evidence submitted in support of the information, or the revised application. An applicant who receives an IAD may appeal under the appeals procedures set out at 15 CFR part 906.

* * * * *

(o) * * *

(4) * * *

(i) * * *

(D) The replacement vessel is not a vessel listed at section 208(e)(1) through (20) of the American Fisheries Act or permitted under paragraph (l)(2)(i) of this section; is not an AFA replacement vessel designated on a listed AFA catcher/processor permit under paragraph (l)(2)of this section; and is not an AFA catcher vessel permitted under paragraph (l)(3) of this section.

* * * * *

4. In § 679.7, revise paragraphs (i)(6), (k)(1)(ii), (k)(1)(iii), (k)(1)(iv), (k)(1)(v), (k)(1)(vi)(A) heading, (k)(1)(vi)(B) heading, (k)(1)(vii)(A) heading, (k)(1)(vii)(B) heading, and (k)(2)(ii) to read as follows:

§ 679.7 Prohibitions.

* * * * *

(i) * * *

(6) Use a vessel to fish for LLP groundfish or crab species, or allow a vessel to be used to fish for LLP groundfish or crab species, that has an LOA that exceeds the MLOA specified on the license that authorizes fishing for LLP groundfish or crab species, except if the person is using the vessel to fish for LLP groundfish in the Bering Sea subarea or the Aleutian Islands subarea pursuant to an LLP license that specifies an exemption from the MLOA on the LLP license.

* * * * *

(k) * * *

(1) * * *

(ii) *Fishing in the GOA.* Use a listed AFA catcher/processor or a catcher/processor designated on a listed AFA catcher/processor permit to harvest any species of fish in the GOA.

(iii) *Processing BSAI crab.* Use a listed AFA catcher/processor or a catcher/processor designated on a listed AFA catcher/processor permit to process any crab species harvested in the BSAI.

(iv) *Processing GOA groundfish.* (A) Use a listed AFA catcher/processor or a catcher/processor designated on a listed AFA catcher/processor permit to process any pollock harvested in a directed pollock fishery in the GOA and any groundfish harvested in Statistical Area 630 of the GOA.

(B) Use a listed AFA catcher/processor or a catcher/processor designated on a listed AFA catcher/processor permit as a stationary floating processor for Pacific cod in the GOA and a catcher/processor in the GOA during the same year.

(v) *Directed fishing after a sideboard closure.* Use a listed AFA catcher/processor or a catcher/processor designated on a listed AFA catcher/processor permit to engage in directed fishing for a groundfish species or species group in the BSAI after the Regional Administrator has issued an AFA catcher/processor sideboard directed fishing closure for that groundfish species or species group under § 679.20(d)(1)(iv) or § 679.21(e)(3)(v).

(vi) * * *

(A) *Listed AFA catcher/processors and catcher/processors designated on listed AFA catcher/processor permits.*

* * *

(B) *Unlisted AFA catcher/processors and catcher/processors designated on unlisted AFA catcher/processor permits.*

* * *

(vii) * * *

(A) *Listed AFA catcher/processors and catcher/processors designated on listed AFA catcher/processor permits.*

* * *

(B) *Unlisted AFA catcher/processors and catcher/processors designated on unlisted AFA catcher/processor permits.*

* * *

* * * * *

(2) * * *

(ii) *Processing GOA groundfish.* Use an AFA mothership as a stationary floating processor for Pacific cod in the GOA and a mothership in the GOA during the same year.

* * * * *

■ 5. In § 679.51, revise paragraphs (a)(2)(vi)(B)(*1*) and (a)(2)(vi)(B)(*3*) to read as follows:

§ 679.51 Observer requirements for vessels and plants.

(a) * * *

(2) * * *

(vi) * * *

(B) * * *

(*1*) *Listed AFA catcher/processors, catcher/processors designated on listed AFA catcher/processor permits, and AFA motherships.* The owner or operator of a listed AFA catcher/processor, a catcher/processor designated on a listed AFA catcher/processor permit, or an AFA mothership must have aboard at least two observers, at least one of whom must be certified

as a lead level 2 observer, for each day that the vessel is used to catch, process, or receive groundfish. More than two observers must be aboard if the observer workload restriction would otherwise preclude sampling as required.

* * * * *

(*3*) *Unlisted AFA catcher/processors and catcher/processors designated on unlisted AFA catcher/processor permits.* The owner or operator of an unlisted AFA catcher/processor or a catcher/processor designated on an unlisted AFA catcher/processor permit must have aboard at least two observers for each day that the vessel is used to engage in directed fishing for pollock in the BSAI, or receive pollock harvested in the BSAI. At least one observer must be certified as a lead level 2 observer. When a listed AFA catcher/processor is not engaged in directed fishing for BSAI pollock and is not receiving pollock harvested in the BSAI, the observer coverage requirements at paragraph (a)(2)(ii) of this section apply.

* * * * *

■ 6. In § 679.62,

■ a. Redesignate paragraph (a)(2) as (a)(3) and paragraph (a)(3) as (a)(4); and

■ b. Add paragraph (a)(2) to read as follows:

§ 679.62 Inshore sector cooperative allocation program.

(a) * * *

(2) *Determination of individual vessel catch histories after approval of replacement of catcher vessel and approval of removal of catcher vessel from the AFA directed pollock fishery.*

(i) If NMFS approves the application of an owner of a catcher vessel that is a member of an inshore vessel cooperative to replace a catcher vessel pursuant to § 679.4(l)(7), NMFS will assign the AFA inshore pollock catch history of the replaced vessel to the replacement vessel.

(ii) If NMFS approves the application of an owner of a catcher vessel that is a member of an inshore vessel cooperative to remove a catcher vessel from the AFA directed pollock fishery pursuant to § 679.4(l)(7), NMFS will assign the AFA inshore pollock catch history of the removed vessel to one or more vessels in the inshore vessel cooperative to which the removed vessel belonged as required by § 679.4(l)(7); NMFS will not assign the catch history for any non-pollock species of the removed vessel to any other vessel, and NMFS will permanently extinguish any exemptions from sideboards that were specified on the AFA permit of the removed vessel.

* * * * *

■ 7. In § 679.63,

■ a. Redesignate paragraph (c) as paragraph (d); and

■ b. Add paragraph (c) to read as follows:

§ 679.63 Catch weighing requirements for vessels and processors.

* * * * *

(c) *What are the requirements for AFA replacement vessels?* The owner and operator of an AFA replacement vessel are subject to the catch weighing requirements and the observer sampling station requirements in paragraphs (a) and (b) of this section that applied to the owner and operator of the replaced vessel.

* * * * *

■ 8. In § 679.64,

■ a. Revise paragraph (a) heading and introductory text, and paragraph (a)(1) heading; and

■ b. Add paragraphs (b)(2)(iii) and (b)(2)(iv) to read as follows:

§ 679.64 Harvesting sideboard limits in other fisheries.

(a) *Harvesting sideboards for listed AFA catcher/processors and catcher/processors designated on listed AFA catcher/processor permits.* The Regional Administrator will restrict the ability of listed AFA catcher/processors and a catcher/processor designated on a listed AFA catcher/processor permit to engage in directed fishing for non-pollock groundfish species to protect participants in other groundfish fisheries from adverse effects resulting from the AFA and from fishery cooperatives in the BS subarea directed pollock fishery.

(1) *How will groundfish sideboard limits for AFA listed catcher/processors and catcher/processors designated on listed AFA catcher/processor permits be calculated?* * * *

* * * * *

(b) * * *

(2) * * *

(iii) An AFA rebuilt catcher vessel will have the same sideboard exemptions, if any, as the vessel before rebuilding, irrespective of the length of the AFA rebuilt catcher vessel.

(iv) An AFA replacement vessel for an AFA catcher vessel will have the same sideboard exemptions, if any, as the replaced AFA catcher vessel, irrespective of the length of the AFA replacement vessel, except that if the replacement vessel was already designated on an AFA permit as exempt from sideboard limits, the replacement vessel will maintain the exemption even if the replaced vessel was not exempt from sideboard limits.

* * * * *

§§ 679.4 and 679.51 [Amended]

■ 9. At each of the locations shown in the ''Location'' column, remove the phrase indicated in the ''Remove'' column and replace it with the phrase indicated in the ''Add'' column for the number of times indicated in the ''Frequency'' column.

Location	Remove	Add	Frequency
§ 679.4(a)(1)(iii)(A) and (a)(1)(iii)(C).	Indefinite	Indefinite unless permit is revoked after vessel is replaced or permit is suspended after vessel is lost.	1
§ 679.4(a)(1)(iii)(B)	Indefinite	Indefinite unless permit is revoked after vessel is replaced or removed, or permit is suspended after vessel is lost.	1
§ 679.51(f)(5)	(a)(2)(vi)(B)(*1*) and (*2*)	(a)(2)(vi)(B)(*1*) through (*3*)	1

[FR Doc. 2014–14012 Filed 6–17–14; 8:45 am]

BILLING CODE 3510–22–P

Notices

Federal Register

Vol. 79, No. 117

Wednesday, June 18, 2014

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

Submission for OMB Review; Comment Request

June 12, 2014.

The Department of Agriculture has submitted the following information collection requirement(s) to OMB for review and clearance under the Paperwork Reduction Act of 1995, Public Law 104–13. Comments regarding (a) whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (b) the accuracy of the agency's estimate of burden including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on 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 should be addressed to: Desk Officer for Agriculture, Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), New Executive Office Building, 725 17th Street NW., Washington, DC 20502. Commenters are encouraged to submit their comments to OMB via email to: *OIRA_Submission@omb.eop.gov* or fax (202) 395–5806 and to Departmental Clearance Office, USDA, OCIO, Mail Stop 7602, Washington, DC 20250–7602. Comments regarding these information collections are best assured of having their full effect if received by July 18, 2014. Copies of the submission(s) may be obtained by calling (202) 720–8681.

An agency may not conduct or sponsor a collection of information unless the collection of information displays a currently valid OMB control number and the agency informs potential persons who are to respond to the collection of information that such persons are not required to respond to the collection of information unless it displays a currently valid OMB control number.

Rural Housing Service

Title: 7 CFR Part 3565, ''Guaranteed Rural Rental Housing Program'' and Its' Supporting Handbook.

OMB Control Number: 0575–0174.

Summary of Collection: On March 26, 1996, the Housing Opportunity Program Extension Act of 1996 was signed. One of the provisions of the Act was the authorization of the section 538 Guaranteed Rural Rental Housing Program (GRRHP), adding the program to the Housing Act of 1949. The purpose of the GRRHP is to increase the supply of affordable rural rental housing through the use of loan guarantees that encourage partnerships between the Rural Housing Service (RHS), private lenders and public agencies. RUS will approve qualified lenders to participate and monitor lender performance to ensure program requirements are met. RHS will collect information from lenders on the eligibility cost, benefits, feasibility, and financial performance of the proposed project.

Need and Use of the Information: RHS will collect information from lenders to manage, plan, evaluate, and account for Government resources and from time to time, propose demonstration programs that use loan guarantees or interest credit. The GRRHP regulation and handbook will provide lenders and agency staff with guidance on the origination, and servicing of GRRHP loans and the approval of qualified lenders. RHS will use the information to evaluate a lender's request and make determination that the interests of the government are protected. Failure to collect information could have an adverse impact on the agency ability to monitor lenders and assess program effectiveness and effectively guarantee loans.

Description of Respondents: Business or other for-profit; Not-for-profit Institutions.

Number of Respondents: 150.

Frequency of Responses: Reporting: Quarterly; Monthly; Annually.

Total Burden Hours: 1,492.

Charlene Parker,

Departmental Information Collection Clearance Officer.

[FR Doc. 2014–14189 Filed 6–17–14; 8:45 am]

BILLING CODE 3410–XV–P

DEPARTMENT OF AGRICULTURE

Submission for OMB Review; Comment Request

June 12, 2014.

The Department of Agriculture has submitted the following information collection requirement(s) to OMB for review and clearance under the Paperwork Reduction Act of 1995, Public Law 104–13. Comments regarding (a) whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (b) the accuracy of the agency's estimate of burden including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on 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.

Comments regarding this information collection received by July 18, 2014 will be considered. Written comments should be addressed to: Desk Officer for Agriculture, Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), New Executive Office Building, 725 17th Street NW., Washington, DC 20502. Commenters are encouraged to submit their comments to OMB via email to: *OIRA_Submission@OMB.EOP.GOV* or fax (202) 395–5806 and to Departmental Clearance Office, USDA, OCIO, Mail Stop 7602, Washington, DC 20250–7602. Copies of the submission(s) may be obtained by calling (202) 720–8958.

An agency may not conduct or sponsor a collection of information unless the collection of information displays a currently valid OMB control number and the agency informs potential persons who are to respond to the collection of information that such

persons are not required to respond to the collection of information unless it displays a currently valid OMB control number.

Animal Plant and Health Inspection Service

Title: Bees and Related Articles.

OMB Control Number: 0579–0207.

Summary of Collection: The Plant Protection Act (APA) (7 U.S.C. 7701 *et seq*), authorizes the Secretary of Agriculture to prohibit or restrict the importation, entry, or interstate movement of plants, plant products, and other articles to prevent the introduction of plant pests into the United States or their dissemination within the United States. Under the Honeybee Act (7 U.S.C. 281–286), the Secretary is authorized to prohibit or restrict the importation of honeybee semen to prevent the introduction into the United States of diseases and parasites harmful to honeybees and of undesirable species and subspecies of honeybees. The Animal and Plant Health Inspection Service (APHIS), Plant Protection and Quarantine (PPQ), is responsible for implementing the intent of these Acts, and does so through the enforcement of its pollinator regulations and honeybee regulations.

Need and Use of the Information: APHIS collects information from a variety of individuals who are involved in breeding, exporting, importing, and containing bees and related articles. The information APHIS collects serves as the supporting documentation needed to issue required PPQ forms and documents that allow importation of bees and related articles or authorizes the release of bees. This documentation is vital to helping APHIS ensure that exotic bee diseases and parasites, and undesirable species and subspecies of honeybees, do not spread into or within the United States. Without the information APHIS could not verify that imported bees and related articles do not present a significant risk of introducing exotic bee disease, parasites, and undesirable species and subspecies of honeybees.

Description of Respondents: Business or other-for-profit; Federal Government.

Number of Respondents: 199.

Frequency of Responses: Recordkeeping; Reporting: On occasion.

Total Burden Hours: 56.

Ruth Brown,

Departmental Information Collection Clearance Officer.

[FR Doc. 2014–14191 Filed 6–17–14; 8:45 am]

BILLING CODE 3410–34–P

DEPARTMENT OF AGRICULTURE

Submission for OMB Review; Comment Request

June 12, 2014.

The Department of Agriculture has submitted the following information collection requirement(s) to OMB for review and clearance under the Paperwork Reduction Act of 1995, Public Law 104–13. Comments regarding (a) whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (b) the accuracy of the agency's estimate of burden including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on 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 should be addressed to: Desk Officer for Agriculture, Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), *OIRA_Submission@OMB.EOP.GOV* or fax (202) 395–5806 and to Departmental Clearance Office, USDA, OCIO, Mail Stop 7602, Washington, DC 20250–7602. Comments regarding these information collections are best assured of having their full effect if received within 30 days of this notification. Copies of the submission(s) may be obtained by calling (202) 720–8958.

An agency may not conduct or sponsor a collection of information unless the collection of information displays a currently valid OMB control number and the agency informs potential persons who are to respond to the collection of information that such persons are not required to respond to the collection of information unless it displays a currently valid OMB control number.

Foreign Agricultural Service

Title: Food Donation Programs (Food for Progress & Section 416(b) and McGovern-Dole International Food for Education and Child Nutrition Program).

OMB control number: 0551–0035.

Summary of Collection: The U.S. Department of Agriculture's Foreign Agricultural Service (FAS) provides U.S. agricultural commodities to feed millions of hungry people in needy countries through direct donations and concessional programs. USDA Food aid may be provided through two program authorities: Food for Progress authorized by the Food for Progress Act of 1985, Section 416(b); and the McGovern-Dole International Food for Education and Child Nutrition Program is authorized by the Food, Conservation, and Energy Act of 2008.

Need and Use of the Information: FAS will collect information from applicants desiring to receive grants under the programs to determine its ability to carry out a food aid program, to establish the terms under which the commodities will be provided, to monitor the progress of commodity distribution (including how transportation is procured), to monitor the progress of expenditure of monetization funds, and to evaluate both the program's success and the participant's effectiveness in meeting the agreed upon goals. Information is also collected from ship owners/brokers shipping the commodity to its destination.

Description of Respondents: Not for-profit institutions; Business or other for-profit.

Number of Respondents: 68.

Frequency of Responses: Recordkeeping; Reporting: Semi-annually; Quarterly.

Total Burden Hours: 112,763.

Ruth Brown,

Departmental Information Collection Clearance Officer.

[FR Doc. 2014–14190 Filed 6–17–14; 8:45 am]

BILLING CODE 3410–10–P

DEPARTMENT OF AGRICULTURE

Submission for OMB Review; Comment Request

June 12, 2014.

The Department of Agriculture has submitted the following information collection requirement(s) to OMB for review and clearance under the Paperwork Reduction Act of 1995, Public Law 104–13. Comments regarding (a) whether the collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility; (b) the accuracy of the agency's estimate of burden including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility and clarity of the information to be collected; (d) ways to minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or

other technological collection techniques and other forms of information technology.

Comments regarding this information collection received by July 18, 2014 will be considered. Written comments should be addressed to: Desk Officer for Agriculture, Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), New Executive Office Building, 725 17th Street NW., Washington, DC 20503. Commentors are encouraged to submit their comments to OMB via email to: *OIRA_Submission@omb.eop.gov* or fax (202) 395–5806 and to Departmental Clearance Office, USDA, OCIO, Mail Stop 7602, Washington, DC 20250–7602. Copies of the submission(s) may be obtained by calling (202) 720–8681.

An agency may not conduct or sponsor a collection of information unless the collection of information displays a currently valid OMB control number and the agency informs potential persons who are to respond to the collection of information that such persons are not required to respond to the collection of information unless it displays a currently valid OMB control number.

Forest Service

Title: Arctic National Wildlife Refuge Visitor Study.

OMB Control Number: 0596–NEW.

Summary of Collection: The Wilderness Act of 1964 directs that the National Wilderness Preservation System be managed to protect natural wilderness conditions and to provide outstanding opportunities for solitude or primitive and unconfined types of recreation. To help meet Federal agencies' mandates related to recreation, scientists at the Aldo Leopold Wilderness Research Institute periodically monitor and report to mangers and the public, visitor use and user characteristics and visitor feedback on management actions on federal lands, including National Wildlife Refuges.

Need and use of the Information: This study will only ask recreation visitors questions about their recreation visit, their personal demographics relevant to education and service provision, and factors that have influenced or are likely to influence their recreation visits. Agency personnel will use the collected information to ensure that visitors' recreational activities do not harm the natural resources of the refuge and that wilderness-type recreation experiences are protected. The collected information will help managers continue to adapt their current programs to changing societal interests and needs; and meet the intent of the legislation that created the Arctic National Wildlife Refuge.

Description of Respondents: Individuals or households.

Number of Respondents: 850.

Frequency of Responses: Reporting: Annually.

Total Burden Hours: 191.

Forest Service

Title: Environmental Justice and the Urban Forest in Atlanta, GA.

OMB Control Number: 0596–NEW.

Summary of Collection: Environmental justice is defined by the Environmental Protection Agency as the ''fair treatment and meaningful involvement of *all* people . . . with respect to the development, implementation, and enforcement of environmental laws . . .'' This information collection addresses environmental justice in urban settings. Cities are often (though not always) places of particular concern for environmental justice inquires due to the greater concentration of environmental pollutants and human populations. The following statutes and regulations are relevant to this request for information collection: Executive Order 12898, Memorandum of Understanding on Environmental Justice and Executive Order 12898, National Environmental Policy Act of 1969 (Pub. L. 91–190), the Civil Rights Act of 1964 (Pub. L. 88–352).

Need and use of the Information: The proposed study provides an integrated approach to assessing residents' relationship to the urban forest. The collection addresses environmental justice from the perspective of urban trees; and how this resource may contribute to environmental justice in a given community or neighborhood. The agency will use this information to determine whether their programs, policies, and activities have disproportionately high and adverse human health or environmental effects on minority populations and low-income populations. If the information is not collected, efforts at the federal level to evaluate environmental justice will remain limited to methodologies that reproduce incomplete assessments of environmental justice.

Description of Respondents: Individuals or households.

Number of Respondents: 824.

Frequency of Responses: Reporting: Other (one time).

Total Burden Hours: 223.

Charlene Parker,

Departmental Information Collection Clearance Officer.

[FR Doc. 2014–14188 Filed 6–17–14; 8:45 am]

BILLING CODE 3411–15–P

COMMISSION ON CIVIL RIGHTS

Agenda and Notice of Public Meeting of the Idaho Advisory Committee

Notice is hereby given, pursuant to the provisions of the rules and regulations of the U.S. Commission on Civil Rights (Commission) and the Federal Advisory Committee Act (FACA) that a planning meeting the Idaho Advisory Committee (Committee) to the Commission will be held on Thursday, July 10, 2014, at the Boise Public Library, 715 S. Capitol Boulevard, Boise, ID 83702. The meeting is scheduled to begin at 1:30 p.m. and adjourn at approximately 3:30 p.m. The purpose of the meeting is for the Committee to plan future project activity.

Members of the public are entitled to submit written comments. The comments must be received in the Western Regional Office of the Commission by August 10, 2014. The address is Western Regional Office, U.S. Commission on Civil Rights, 300 N. Los Angeles Street, Suite 2010, Los Angeles, CA 90012. Persons wishing to email their comments, or to present their comments verbally at the meeting, or who desire additional information should contact Angelica Trevino, Civil Rights Analyst, Western Regional Office, at (213) 894–3437, (or for hearing impaired TDD 913–551–1414), or by email to *atrevino@usccr.gov.* Hearing-impaired persons who will attend the meeting and require the services of a sign language interpreter should contact the Regional Office at least ten (10) working days before the scheduled date of the meeting.

Records generated from this meeting may be inspected and reproduced at the Western Regional Office, as they become available, both before and after the meeting. Persons interested in the work of this advisory committee are advised to go to the Commission's Web site, *www.usccr.gov,* or to contact the Western Regional Office at the above email or street address. The meeting will be conducted pursuant to the provisions of the rules and regulations of the Commission and FACA.

Dated June 13, 2014.

David Mussatt,

Acting Chief, Regional Programs Coordination Unit.

[FR Doc. 2014–14237 Filed 6–17–14; 8:45 am]

BILLING CODE 6335–01–P

DEPARTMENT OF COMMERCE

Submission for OMB Review; Comment Request

The Department of Commerce will submit to the Office of Management and Budget (OMB) for clearance the following proposal for collection of information under the provisions of the Paperwork Reduction Act (44 U.S.C. Chapter 35).

Agency: National Oceanic and Atmospheric Administration (NOAA).

Title: Reporting Requirements for the Ocean Salmon Fishery Off the Coasts of Washington, Oregon, and California.

OMB Control Number: 0648–0433.

Form Number(s): NA.

Type of Request: Regular submission (extension of a current information collection).

Number of Respondents: 40.

Average Hours Per Response: 15 minutes.

Burden Hours: 40.

Needs and Uses: This request is for extension of a currently approved information collection.

Based on the management regime specified each year, designated regulatory areas in the commercial ocean salmon fishery off the coasts of Washington, Oregon, and California may be managed by numerical quotas. To accurately assess catches relative to quota attainment during the fishing season, catch data by regulatory areas must be collected in a timely manner. Requirements to land salmon within specific time frames and in specific areas may be implemented in the preseason regulations to aid in timely and accurate catch accounting for a regulatory area. State landing systems normally gather the data at the time of landing. If unsafe weather conditions or mechanical problems prevent compliance with landing requirements, fishermen need an alternative to allow for a safe response. Fishermen would be exempt from landing requirements if the appropriate notifications are made to provide the name of the vessel, the port where delivery will be made, the approximate amount of salmon (by species) on board, and the estimated time of arrival.

Affected Public: Business or other for-profit organizations.

Frequency: On occasion.

Respondent's Obligation: Mandatory.

This information collection request may be viewed at *reginfo.gov*. Follow the instructions to view Department of Commerce collections currently under review by OMB.

Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *OIRA_Submission@omb.eop.gov* or faxed to (202) 395–5806.

Dated: June 12, 2014.

Gwellnar Banks,

Management Analyst, Office of the Chief Information Officer.

[FR Doc. 2014–14205 Filed 6–17–14; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

Submission for OMB Review; Comment Request

The Department of Commerce will submit to the Office of Management and Budget (OMB) for clearance the following proposal for collection of information under the provisions of the Paperwork Reduction Act (44 U.S.C. Chapter 35).

Agency: National Oceanic and Atmospheric Administration (NOAA).

Title: Alaska Region BSAI Crab Permits.

OMB Control Number: 0648–0514.

Form Number(s): NA.

Type of Request: Regular submission (revision and extension of a current information collection).

Number of Respondents: 515.

Average Hours Per Response: Annual application for crab IFQ permit, application for Crab IPQ permit, application to become an eligible crab community organization (ECCO), 150 minutes each; application for an Annual Crab Harvesting Cooperative IFQ Permit, Right of first refusal (ROFR) contracts and waivers, 1 hour each; annual application for Crab Converted CPO QS and CPO IFQ and application for Registered Crab Receiver (RCR) Permit, BSAI Crab Rationalization Program Quota Share Beneficiary Designation Form, 30 minutes; application for Crab IFQ Hired Master Permit and application for Federal crab vessel permit (FCVP), 21 minutes each; application for eligibility to receive crab QS/IFQ or PQS/IPQ by transfer, application for transfer of crab IFQ, application for transfer of crab QS/IFQ to or from an ECCO, Application to transfer crab QS or PQS, application for Annual Exemption from Western Aleutian Islands Golden King Crab West Region Delivery Requirements, Community Impact Report or IPQ Holder Report (North or South Response Report), 2 hours each; ECCO Annual report and appeal of denial to NMFS decisions, 4 hours each; application for transfer of IFQ between crab harvesting cooperatives, electronic, 5 minutes, non-electronic, 2 hours; application to Transfer Crab IPQ, electronic, 1 hour; non-electronic, 2 hours; CDQ notification of community representative, 5 hours; application for exemption from CR Crab North or South Region Delivery Requirements and North or South Region Delivery Exemption Report, 20 hours each.

Burden Hours: 1,621.

Needs and Uses: This request is for a revision and extension of a currently approved information collection.

The king and Tanner crab fisheries in the exclusive economic zone of the Bering Sea and Aleutian Islands, Alaska, are managed under the Fishery Management Plan for Bering Sea and Aleutian Islands King and Tanner Crabs (FMP). The North Pacific Fishery Management Council prepared the FMP under the Magnuson-Stevens Fishery Conservation and Management Act as amended in 2006. National Marine Fisheries Service (NMFS) manages the crab fisheries in the waters off the coast of Alaska under the FMP. Regulations implementing the FMP and all amendments to the Crab Rationalization Program (CR Program) appear at 50 CFR part 680. Program details are found at: *http://www.alaskafisheries.noaa.gov/regs/680/default.htm*.

The CR Program balances the interests of several groups who depend on the crab fisheries. The CR Program addresses conservation and management issues associated with the previous derby fishery, reduces bycatch and associated discard mortality, and increases the safety of crab fishermen by ending the race for fish. Share allocations to harvesters and processors, together with incentives to participate in fishery cooperatives, increases efficiencies, provides economic stability, and facilitates compensated reduction of excess capacities in the harvesting and processing sectors. Community interests are protected by Western Alaska Community Development Quota allocations and regional landing and processing requirements, as well as by several community protection measures.

The NMFS established the CR Program as a catch share program for nine crab fisheries in the Bering Sea and Aleutian Islands (BSAI), and assigned quota share (QS) to persons and processor quota share (PQS) to processors based on their historic participation in one or more of these nine crab fisheries during a specific period. The CR Program components include QS allocation, PQS allocation, individual fishing quota (IFQ) issuance, and individual processing quota (IPQ) issuance, quota transfers, use caps, crab harvesting cooperatives, protections for

Gulf of Alaska groundfish fisheries, arbitration system, monitoring, economic data collection, and cost recovery fee collection. Revision: the eligible crab community organization (ECCO) annual report has been moved from OMB Control No. 0648–0570.

Affected Public: Business or other for-profit organizations.

Frequency: Annually and on occasion.

Respondent's Obligation: Required to obtain or retain benefits.

This information collection request may be viewed at *reginfo.gov*. Follow the instructions to view Department of Commerce collections currently under review by OMB.

Written comments and recommendations for the proposed information collection should be sent within 30 days of publication of this notice to *OIRA_Submission@omb.eop.gov* or faxed to (202) 395–5806.

Dated: June 12, 2014.

Gwellnar Banks,

Management Analyst, Office of the Chief Information Officer.

[FR Doc. 2014–14206 Filed 6–17–14; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

[Docket No. 140421355–4496–02]

Privacy Act New System of Records

AGENCY: Department of Commerce.

ACTION: Notice; Commerce/Department-24, BusinessUSA Intellectual Hosting Service Application and Satisfaction Survey Records.

SUMMARY: The Department of Commerce (Commerce) publishes this notice to announce the effective date of a Privacy Act System of Records entitled Commerce/Department-24, BusinessUSA Intellectual Hosting Service Application and Satisfaction Survey Records. The notice of proposed amendment to this system of records was published in the **Federal Register** on May 13, 2014.

DATES: The system of records becomes effective on June 18, 2014.

ADDRESSES: For a copy of the system of records please mail requests to Efrain Gonzalez, Jr., BusinessUSA, U.S. Department of Commerce, Room 2830, 1401 Constitution Avenue NW., Washington, DC 20230.

FOR FURTHER INFORMATION CONTACT: Efrain Gonzalez, Jr., Chief Financial Officer/Chief Administrative Officer, BusinessUSA, 202–482–6407.

SUPPLEMENTARY INFORMATION: On May 13, 2014, the Department of Commerce published and requested comments on a proposed Privacy Act System of Records entitled Commerce/Department-24, BusinessUSA Intellectual Hosting Service Application and Satisfaction Survey Records (79 FR 92). No comments were received in response to the request for comments. By this notice, the Department is adopting the proposed system as final without changes effective June 18, 2014.

Dated: June 13, 2014.

Brenda Dolan,

U.S. Department of Commerce, Freedom of Information and Privacy Act Officer.

[FR Doc. 2014–14222 Filed 6–17–14; 8:45 am]

BILLING CODE 3510–17–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–428–840]

Lightweight Thermal Paper From Germany: Final Results of Antidumping Duty Administrative Review; 2011–2012

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: On December 16, 2013, the Department of Commerce (the Department) published the preliminary results of the administrative review of the antidumping duty order on lightweight thermal paper from Germany.[1] The period of review (POR) is November 1, 2011, through October 31, 2012. We invited interested parties to comment on the preliminary results. After reviewing the comments received and making one correction to the margin calculation program, we continue to find that Papierfabrik August Koehler SE (Koehler) did not make sales of subject merchandise at less than normal value. The final dumping margin for Koehler, listed below in the section entitled ''Final Results of Review,'' is unchanged from the preliminary results. In addition, we find that Papierfabrik August Koehler SE is the successor-in-interest to Papierfabrik August Koehler AG.

DATES: Effective Date: June 18, 2014.

FOR FURTHER INFORMATION CONTACT: David Goldberger, AD/CVD Operations, Office II, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue NW., Washington, DC 20230; telephone (202) 482–4136.

[1] *See Lightweight Thermal Paper from Germany; Preliminary Results of Antidumping Duty Administrative Review; 2011–2012,* 78 FR 78335 (December 26, 2013) (*Preliminary Results*).

Background

Since the publication of the *Preliminary Results,* the following events have occurred. In February 2014, the petitioner, Appvion, Inc., and Koehler each submitted case and rebuttal briefs. On March 13, 2014, we held both a public and a closed hearing hearing at the request of the petitioner.

The Department conducted this administrative review in accordance with section 751(a)(1) of the Tariff Act of 1930, as amended (the Act).

Scope of the Order

The merchandise covered by the order is lightweight thermal paper. The merchandise subject to the order is currently classified under the following Harmonized Tariff Schedule of the United States (HTSUS) subheadings: 3703.10.60, 4811.59.20, 4811.90.8000, 4811.90.8030, 4811.90.8040, 4811.90.8050, 4811.90.9000, 4811.90.9030, 4811.90.9035, 4811.90.9050, 4811.90.9080, 4811.90.9090, 4820.10.20, and 4823.40.00. Although the HTSUS numbers are provided for convenience and customs purposes, the written product description, available in the *Order,* remains dispositive.[2]

Analysis of Comments Received

All issues raised in the case and rebuttal briefs by parties are addressed in the memorandum entitled, ''Issues and Decision Memorandum for the Final Results of the 2011–2012 Administrative Review on Lightweight Thermal Paper from Germany'' (Issues and Decision Memo), which is dated concurrently with, and adopted by, this notice. A list of the issues which parties raised and to which we respond in the Issues and Decision Memo is attached to this notice as Appendix I. The Issues and Decision Memo is a public document and is on file electronically via Enforcement and Compliance's Antidumping and Countervailing Duty Centralized Electronic Service System (IA ACCESS). IA ACCESS is available to registered users at *http://iaaccess.trade.gov* and is available to all parties in the Central Records Unit (CRU), room 7046 of the main Department of Commerce building. In addition, a complete version of the Issues and Decision Memo can be

[2] For a complete description of the scope, *see Antidumping Duty Orders: Lightweight Thermal Paper from Germany and the People's Republic of China,* 73 FR 70959 (November 24, 2008) (*Order*). *See also Preliminary Results* and accompanying Decision Memorandum for Preliminary Results of Antidumping Duty Administrative Review: Lightweight Thermal Paper from Germany (Preliminary Decision Memorandum).

accessed directly on the Internet at *http://enforcement.trade.gov/frn/*. The signed Issues and Decision Memo and the electronic version of the Issues and Decision Memo are identical in content.

Final Results of the Review

As a result of this review, we determine that the following weighted-average dumping margin exists for the period November 1, 2011, through October 31, 2012.

Manufacturer/exporter	Percent margin
Papierfabrik August Koehler SE ...	0.00

Disclosure

We intend to disclose the calculations performed within five days of the date of publication of this notice to parties in this proceeding in accordance with 19 CFR 351.224(b).

Assessment Rates

The Department will determine, and U.S. Customs and Border Protection (CBP) shall assess, antidumping duties on all appropriate entries, in accordance with 19 CFR 351.212(b). The Department intends to issue appropriate assessment instructions directly to CBP 15 days after publication of these final results of review. Because we have calculated a zero margin for Koehler in the final results of this review, we will instruct CBP to liquidate the appropriate entries without regard to antidumping duties.

The Department clarified its ''automatic assessment'' regulation on May 6, 2003. *See Antidumping and Countervailing Duty Proceedings: Assessment of Antidumping Duties,* 68 FR 23954 (May 6, 2003) (*Assessment Policy Notice*). This clarification applies to entries of subject merchandise during the POR produced by Koehler for which it did not know that the merchandise was destined for the United States. In such instances, we will instruct CBP to liquidate unreviewed entries at the all-others rate effective during the POR if there is no rate for the intermediate company(ies) involved in the transaction. *See Assessment Policy Notice* for a full discussion of this clarification.

Cash Deposit Requirements

The following cash deposit requirements will be effective for all shipments of lightweight thermal paper from Germany 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) For Koehler, the calculated weighted-average margin rate is 0.00 percent and, accordingly, no cash deposit will be required; (2) for previously reviewed or investigated companies not participating in this review, 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 previous review, or the original 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 6.50 percent, the all-others rate established in the investigation.[3] These deposit requirements, when imposed, shall remain in effect until further notice.

Notification to Importers

This notice also serves as a final 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 the Secretary's presumption that reimbursement of antidumping duties occurred and the subsequent assessment of double antidumping duties.

Notification Regarding Administrative Protective Orders

This notice serves as the only reminder to parties subject to administrative protective order (APO) of their responsibility concerning the disposition of proprietary information disclosed under APO in accordance with 19 CFR 351.305(a)(3). Timely written notification of return or destruction of APO materials or conversion to judicial protective order is hereby requested. Failure to comply with the regulations and the terms of an APO is a sanctionable violation.

This administrative review and notice are published in accordance with sections 751(a)(1) and 777(i)(1) of the Act and 19 CFR 351.221.

[3] *See Order.*

Dated: June 11, 2014.

Ronald K. Lorentzen,

Acting Assistant Secretary for Enforcement and Compliance.

Appendix I

List of Topics Discussed in the Issues and Decision Memo

1. Exclusion of Certain Sales from Normal Value (NV) Calculations
2. Application of Adverse Facts Available (AFA) to Unreported U.S. Sales Quantity
3. Recalculation of Indirect Selling Expenses Incurred in the United States
4. Differential Pricing and Application of Average-to-Transaction Methodology
5. Ministerial Errors in Margin Calculation Program

[FR Doc. 2014–14243 Filed 6–17–14; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–583–008]

Certain Circular Welded Carbon Steel Pipes and Tubes From Taiwan: Preliminary Results of Antidumping Duty Administrative Review; 2012–2013

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The Department of Commerce (the Department) is conducting an administrative review of the antidumping duty order on certain circular welded carbon steel pipes and tubes from Taiwan. The period of review (POR) is May 1, 2012, through April 30, 2013, and the review covers Shin Yang Steel Co., Ltd. (Shin Yang), a producer and exporter of subject merchandise. We preliminarily find that sales of the subject merchandise were not made at prices below normal value.

DATES: *Effective Date:* June 18, 2014.

FOR FURTHER INFORMATION CONTACT: Steve Bezirganian or Robert James, AD/CVD Operations, Office VI, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue NW., Washington, DC 20230; telephone: (202) 482–1131 or (202) 482–0649, respectively.

SUPPLEMENTARY INFORMATION:

Scope of the Order

The merchandise subject to the order is certain circular welded carbon steel pipes and tubes from Taiwan. The product is currently classified under the Harmonized Tariff Schedule of the United States (HTSUS) item numbers 7306.30.5025, 7306.30.5032,

7306.30.5040, and 7306.30.5055. Although the HTSUS numbers are provided for convenience and customs purposes, the written product description remains dispositive.[1]

Methodology

For a full description of the methodology underlying our conclusions, please see the Preliminary Decision Memorandum.[2] 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 (IA ACCESS). Access to IA ACCESS is available to registered users at *http://iaaccess.trade.gov* and to all parties in the Central Records Unit (CRU), room 7046 of the main Department of Commerce building. In addition, a complete version of the Preliminary Decision Memorandum can be accessed directly on the Internet at *http://enforcement.trade.gov/frn/*. The signed Preliminary Decision Memorandum and the electronic versions of the Preliminary Decision Memorandum are identical in content.

The Department is conducting this review in accordance with section 751(a)(2) of the Tariff Act of 1930, as amended (the Act). Export Price is calculated in accordance with section 772 of the Act. Normal value is calculated in accordance with section 773 of the Act. For a full description of the methodology underlying our conclusions, please see the Preliminary Decision Memorandum.

Preliminary Results of the Review

As a result of this review, we preliminarily determine that a weighted-average dumping margin of 0.00 percent exists for Shin Yang for the POR.

Disclosure and Public Comment

The Department intends to disclose to interested parties the calculations performed in connection with these preliminary results within five days of the date of publication of this notice.[3] Pursuant to 19 CFR 351.309(c), interested parties may submit case briefs no 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 no later than five days after the date for filing case briefs.[4] Parties who submit case briefs 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.[5] Case and rebuttal briefs should be filed using IA ACCESS.[6] An electronically filed document must be received successfully in its entirety by the Department's electronic records system IA ACCESS, by 5 p.m. Eastern Time on the day on which it is due.

Pursuant to 19 CFR 351.310(c), 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 Import Administration, filed electronically via IA ACCESS within 30 days after the date of publication of this notice.[7] Requests should contain: (1) The party's name, address and telephone number; (2) the number of participants; and (3) a list of issues to be discussed. Issues raised in the hearing will be limited to those raised in the respective case briefs.

The Department will issue the final results of this administrative review, including the results of its analysis of the issues raised in any written briefs, not later than 120 days after the date of publication of this notice, pursuant to section 751(a)(3)(A) of the Act.

Assessment Rates

Upon completion of this administrative review, pursuant to 19 CFR 351.212(b), the Department will calculate importer-specific assessment rates for each respondent whose weighted-average dumping margin is not zero or *de minimis* (*i.e.,* less than 0.5 percent). If a respondent's weighted-average dumping margin is zero or *de minimis,* then the Department will instruct U.S. Customs and Border Protection (CBP) to liquidate all appropriate entries without regard to antidumping duties. The Department intends to issue appropriate assessment instructions directly to CBP 15 days after the date of publication of the final results of this review.

If the weighted-average dumping margin for Shin Yang is not zero or *de minimis* in the final results, then the Department will calculate importer-specific assessment rates. Because Shin Yang did not report the entered value of its sales, we will calculate importer-specific per-unit duty assessment rates by aggregating the total amount of dumping calculated for the examined sales of each importer and dividing each of these amounts by the total quantity (*i.e.,* weight) associated with those sales. To determine whether the importer-specific per-unit assessment rates are *de minimis,* in accordance with the requirement set forth in 19 CFR 351.106(c)(2), we will calculate importer-specific *ad valorem* rates based on estimated entered values. Pursuant to 19 CFR 351.106(c)(2), we will instruct CBP to liquidate without regard to antidumping duties all entries for which the importer-specific *ad valorem* rate is zero or *de minimis*.

The Department clarified its automatic assessment regulation on May 6, 2003.[8] This clarification will apply to entries of subject merchandise during the POR produced by Shin Yang for which the record of this administrative review indicates they did not know was destined for the United States. In such instances, we will instruct CBP to liquidate these entries at the all-others rate if there is no rate for the intermediate company(ies) involved in the transaction.

Cash Deposit Requirements

The following cash deposit requirements for estimated antidumping duties will be effective upon publication of the notice of final results of administrative review for all shipments of certain circular welded carbon steel pipes and tubes from Taiwan entered, or withdrawn from warehouse, for consumption on or after the date of publication as provided by section 751(a)(2) of the Act: (1) The cash deposit for Shin Yang will be equal to the weighted-average dumping margin established in the final results of this administrative review; (2) for merchandise exported by manufacturers or exporters not covered in this review but covered in a previously completed segment of this proceeding, the cash deposit rate will continue to be the company-specific rate published for the most recently completed segment of this proceeding in which that manufacturer or exporter participated; (3) if the

[1] The complete description of the scope of the order appears in the memorandum from Christian Marsh, Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations, to Paul Piquado, Assistant Secretary for Enforcement and Compliance, ''Decision Memorandum for Preliminary Results of Antidumping Duty Administrative Review: Certain Circular Welded Carbon Steel Pipes and Tubes from Taiwan; 2012–2013'' (dated concurrently with this notice) (Preliminary Decision Memorandum), which is hereby adopted by this notice.

[2] A list of the topics discussed in the Preliminary Decision Memorandum appears in the Appendix of this notice.

[3] *See* 19 CFR 351.224(b).

[4] *See* 19 CFR 351.309(d).

[5] *See* 19 CFR 351.309(c)(2) and (d)(2).

[6] *See* 19 CFR 351.303.

[7] *See* 19 CFR 351.310(c).

[8] For a full discussion of this clarification, *see Antidumping and Countervailing Duty Proceedings: Assessment of Antidumping Duties,* 68 FR 23954 (May 6, 2003).

exporter is not a firm covered in this review, a prior review, or the original investigation but the manufacturer is, the cash deposit rate will be the rate established for the most recently completed segment of this proceeding in which that manufacturer or exporter participated; and (4) the cash deposit rate for all other manufacturers or exporters will continue to be 9.70 percent, the all-others rate referenced in *Certain Circular Welded Carbon Steel Pipes and Tubes From Taiwan: Antidumping Duty Order,* 49 FR 19369 (May 7, 1984). These cash deposit requirements, when imposed, shall remain in effect until further notice.

Notifications

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 duties prior to liquidation of the relevant entries during this review period. Failure to comply with this requirement could result in the Secretary's presumption that reimbursement of antidumping duties occurred and the subsequent assessment of double antidumping duties.

This notice also serves as a preliminary reminder to parties subject to administrative protective order (APO) of their responsibility concerning the disposition of proprietary information disclosed under APO in accordance with 19 CFR 351.305(a)(3). Timely written notification of the return or destruction of APO materials, or conversion to judicial protective order, will be requested. Failure to comply with the regulations and the terms of an APO is a sanctionable violation.

We are issuing and publishing these results in accordance with sections 751(a)(1) and 777(i)(1) of the Act and 19 CFR 351.213(h)(1).

Dated: June 10, 2014.

Paul Piquado,

Assistant Secretary for Enforcement and Compliance.

Appendix

List of Topics Discussed in the Preliminary Decision Memorandum

Summary
Background
Scope of the Order
Fair Value Comparisons
Product Comparisons
Determination of Comparison Method
Results of the Differential Pricing Analysis
Date of Sale
Export Price
Level of Trade
Normal Value
Currency Conversion
Conclusion

[FR Doc. 2014–14291 Filed 6–17–14; 8:45 am]

BILLING CODE 3510–DS–P

DEPARTMENT OF COMMERCE

United States Patent and Trademark Office

Patent Examiner Employment Application

ACTION: Notice.

SUMMARY: The United States Patent and Trademark Office (USPTO), as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on the continuing information collection, as required by the Paperwork Reduction Act of 1995, Public Law 104–13 (44 U.S.C. 3506(c)(2)(A)).

DATES: Written comments must be submitted on or before August 18, 2014.

ADDRESSES: You may submit comments by any of the following methods:

- *Email: InformationCollection@uspto.gov.* Include ''0651–0042 comment'' in the subject line of the message.
- *Mail:* Susan K. Fawcett, Records Officer, Office of the Chief Information Officer, United States Patent and Trademark Office, P.O. Box 1450, Alexandria, VA 22313–1450.
- *Federal Rulemaking Portal: http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Requests for additional information should be directed to the attention of LaRita Jones, Chief of the Workforce Employment Division, Office of Human Resources, United States Patent and Trademark Office (USPTO), P.O. Box 1450, Alexandria, VA 22313–1450; by telephone at 571–272–6196; or by email to *larita.jones@uspto.gov.*

SUPPLEMENTARY INFORMATION:

I. Abstract

In the current employment environment, information technology professionals and engineering graduates are in great demand. The USPTO is in direct competition with private industry for the same caliber of candidates with the requisite knowledge and skills to perform patent examination work. The use of automated online systems allows the USPTO to remain competitive, meet hiring goals, and fulfill the agency's Congressional commitment to reduce the pendency rate for the examination of patent applications. The information supplied by an applicant seeking a patent examiner position with the USPTO assists the Human Resources Specialists and hiring managers in determining whether an applicant possesses the basic qualification requirements for the patent examiner position.

The Monster Hiring Management (MHM) system is an automated online system that allows the USPTO to rapidly review applications for employment of entry-level patent examiners. The Office of Human Resources (OHR) can use the system to rapidly review applications for employment and take the necessary administrative action to support the hiring process.

The online application creates an electronic real-time candidate inventory that allows the USPTO to review applications from potential applicants almost instantaneously. Given the immediate hiring need of the Patent Examining Corps, time consumed in the mail distribution system or paper review of applications delays the decision-making process by several weeks. The MHM system results in increased speed and accuracy in the employment process, in addition to streamlining labor and reducing costs.

The use of the MHM online application fully complies with 5 U.S.C. § 2301, which requires adequate public notice to assure open competition by guaranteeing that necessary employment information will be accessible and available to the public on inquiry. It is also fully compliant with Section 508 (29 U.S.C. § 794(d)), which requires agencies to provide disabled employees and members of the public access to information that is comparable to the access available to others.

II. Method of Collection

With the use of MHM, the application information is collected electronically from the applicant. The USAJobs.gov Web site provides the online job announcement that links the applicant to the application and the MHM system. The application is completed online and then transmitted to the USPTO via the Internet.

III. Data

OMB Number: 0651–0042.

Form Number(s): N/A.

Type of Review: Extension of a currently approved collection.

Affected Public: Individuals or households.

Estimated Number of Respondents: 16,103 responses per year.

Estimated Time per Response: The USPTO estimates that it will take the public approximately 30 minutes (0.5 hours) to complete the employment

application, depending upon the applicant's situation.

Estimated Total Annual Respondent Burden Hours: 8,051.5 hours.

Item No.	Item	Estimated time for response (minutes)	Estimated annual responses	Estimated annual burden hours
1	Patent Examiner Employee Application	30	16,103	8,051.5
Total			16,103	8,051.5

Estimated Total Annual Respondent Cost Burden: $359,822. Using the median hourly rate for scientists and engineers of $44.69 as derived from the Bureau of Labor Statistics, the USPTO estimates $359,822 per year in cost burden associated with respondents. This is a fully loaded hourly rate.

Estimated Total Annual (Non-hour) Respondent Cost Burden: $0. There are no filing fees or start-up, maintenance, record keeping, or postage costs associated with this information collection.

IV. Request for Comments

Comments submitted in response to this notice will be summarized and/or included in the request for OMB approval. All comments will become a matter of public record.

The USPTO is soliciting public comments to: (a) 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; (b) 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; (c) Enhance the quality, utility, and clarity of the information to be collected; and (d) 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.

Dated: June 13, 2014.

Susan K. Fawcett,

Records Officer, USPTO, Office of the Chief Information Officer.

[FR Doc. 2014–14214 Filed 6–17–14; 8:45 am]

BILLING CODE 3510–16–P

CORPORATION FOR NATIONAL AND COMMUNITY SERVICE

Guidance for Agency Information Collection Activities: Proposed Collection; Comment Request; Generic Clearance for the Collection of Pilot and Test Data

AGENCY: Corporation for National and Community Service (CNCS).

ACTION: Guidance for CNCS Notices, with request for comments.

SUMMARY: CNCS is submitting the below information for future CNCS **Federal Register** Notices in accordance with the Paperwork Reduction Act of 1995, Pub. L. 104–13, (44 U.S.C. Chapter 35). As part of a Federal Government-wide effort to streamline the process to seek feedback from the public on service delivery, OMB is coordinating the development of the following proposed Generic Information Collection Request (Generic ICR): ''Generic Clearance for the Collection of Pilot and Test Data'' for approval under the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*). This notice announces that CNCS intends to submit collections to OMB for approval and solicit comments on specific aspects for the proposed information collection.

DATES: Comments must be submitted July 18, 2014.

ADDRESSES: Comments may be submitted, identified by the title of the information collection activity, to the Office of Information and Regulatory Affairs, Attn: Ms. Sharon Mar, OMB Desk Officer for CNCS, by any of the following two methods within 30 days from the date of publication in the **Federal Register**:

(1) By fax to: 202–395–6974, Attention: Ms. Sharon Mar, OMB Desk Officer for CNCS; and

(2) Electronically by email to: *smar@omb.eop.gov.*

FOR FURTHER INFORMATION CONTACT: To request additional information, please contact Amy Borgstrom, Associate Director of Policy, at 202–606–6930 or email to *aborgstrom@cns.gov.* Individuals who use a telecommunications device for the deaf (TTY–TDD) may call 1–800–833–3722 between 8:00 a.m. and 8:00 p.m. Eastern Time, Monday through Friday.

SUPPLEMENTARY INFORMATION:

Title: Generic Clearance for the Collection of Pilot and Test Data.

Abstract: This is a new information collection. The information collection activity will enable pilot testing of survey instruments in an efficient, timely manner, in accordance with the Administration's commitment to improving service delivery. By pilot testing we mean information that provides useful insights on how respondents interact with the instrument, but are not statistical surveys that yield quantitative results that can be generalized to the population of study. This feedback will provide insights into customer or stakeholder perceptions, experiences and expectations regarding prospective studies. It will also allow feedback to contribute directly to the improvement of research program management.

The Agency will only submit a collection for approval under this generic clearance if it meets the following conditions:

- The collections are voluntary;
- The collections are low-burden for respondents (based on considerations of total burden hours, total number of respondents, or burden-hours per respondent) and are low-cost for both the respondents and the Federal Government;
- The collections are non-controversial and do not raise issues of concern to other Federal agencies;
- Any collection is targeted to the solicitation of opinions from respondents who have experience with the program or may have experience with the program in the near future;
- Personally identifiable information (PII) is collected only to the extent necessary and is not retained;
- Information gathered will be used only internally for general service improvement and program management purposes and is not intended for release outside of the agency;
- Information gathered will not be used for the purpose of substantially informing influential policy decisions; and

• Information gathered will yield qualitative information; the collections will not be designed or expected to yield statistically reliable results or used as though the results are generalizable to the population of study.

Feedback collected under this generic clearance provides useful information, but it does not yield data that can be generalized to the overall population. This type of generic clearance for qualitative information will not be used for quantitative information collections that are designed to yield reliably actionable results, such as monitoring trends over time or documenting program performance. Such data uses require more rigorous designs that address the target population to which generalizations will be made, the sampling frame, the sample design (including stratification and clustering), the precision requirements or power calculations that justify the proposed sample size, the expected response rate, methods for assessing potential non-response bias, the protocols for data collection, and any testing procedures that were or will be undertaken prior to fielding the study. Depending on the degree of influence the results are likely to have, such collections may still be eligible for submission for other generic mechanisms that are designed to yield quantitative results.

As a general matter, information collections will not result in any new system of records containing privacy information and will not ask questions of a sensitive nature, such as sexual behavior and attitudes, religious beliefs, and other matters that are commonly considered private.

No comments were received in response to the 60-day notice published in the **Federal Register** of March 5, 2014 (79 FR 12495).

Current Actions: New collection of information.

Type of Review: New Collection.

Affected Public: Individuals and Households, Businesses and Organizations, State, Local or Tribal Government.

Average Expected Annual Number of Activities: 10.

Respondents: 350.

Annual responses: 350.

Frequency of Response: Once per request.

Average minutes per response: 30.

Burden hours: 10,500.

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 Office of Management and Budget Control Number.

Dated: June 12, 2014.

Amy Borgstrom,

Associate Director of Policy.

[FR Doc. 2014–14224 Filed 6–17–14; 8:45 am]

BILLING CODE 6050–28–P

CORPORATION FOR NATIONAL AND COMMUNITY SERVICE

Guidance for Agency Information Collection Activities: Proposed Collection; Comment Request; Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery

AGENCY: Corporation for National and Community Service (CNCS).

ACTION: Guidance for CNCS Notices, with request for comments.

SUMMARY: CNCS is submitting the below information for future CNCS **Federal Register** Notices in accordance with the Paperwork Reduction Act of 1995, Public Law 104–13, (44 U.S.C. Chapter 35). As part of a Federal Government-wide effort to streamline the process to seek feedback from the public on service delivery, OMB is coordinating the development of the following proposed Generic Information Collection Request (Generic ICR): ''Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery'' for approval under the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 et seq.). This notice announces that CNCS intends to submit collections to OMB for approval and solicit comments on specific aspects for the proposed information collection.

DATES: Comments must be submitted July 18, 2014.

ADDRESSES: Comments may be submitted, identified by the title of the information collection activity, to the Office of Information and Regulatory Affairs, Attn: Ms. Sharon Mar, OMB Desk Officer for CNCS, by any of the following two methods within 30 days from the date of publication in the **Federal Register**:

(1) By fax to: 202–395–6974, Attention: Ms. Sharon Mar, OMB Desk Officer for CNCS; and

(2) Electronically by email to: *smar@omb.eop.gov.*

FOR FURTHER INFORMATION CONTACT: To request additional information, please contact Amy Borgstrom, Associate Director of Policy, at 202–606–6930 or email to *aborgstrom@cns.gov.* Individuals who use a telecommunications device for the deaf (TTY–TDD) may call 1–800–833–3722 between 8:00 a.m. and 8:00 p.m. Eastern Time, Monday through Friday.

SUPPLEMENTARY INFORMATION:

Title: Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery.

Abstract: The information collection activity will garner qualitative customer and stakeholder feedback in an efficient, timely manner, in accordance with the Administration's commitment to improving service delivery. By qualitative feedback we mean information that provides useful insights on perceptions and opinions, but are not statistical surveys that yield quantitative results that can be generalized to the population of study. This feedback will provide insights into customer or stakeholder perceptions, experiences and expectations, provide an early warning of issues with service, or focus attention on areas where communication, training or changes in operations might improve delivery of products or services. These collections will allow for ongoing, collaborative and actionable communications between the Agency and its customers and stakeholders. It will also allow feedback to contribute directly to the improvement of program management.

Feedback collected under this generic clearance will provide useful information, but it will not yield data that can be generalized to the overall population. This type of generic clearance for qualitative information will not be used for quantitative information collections that are designed to yield reliably actionable results, such as monitoring trends over time or documenting program performance. Such data uses require more rigorous designs that address the target population to which generalizations will be made, the sampling frame, the sample design (including stratification and clustering), the precision requirements or power calculations that justify the proposed sample size, the expected response rate, methods for assessing potential non-response bias, the protocols for data collection, and any testing procedures that were or will be undertaken prior fielding the study. Depending on the degree of influence the results are likely to have, such collections may still be eligible for submission for other generic mechanisms that are designed to yield quantitative results.

No comments were received in response to the 60-day notice published in the **Federal Register** of March 5, 2014 (79 FR 12493).

Current Actions: New collection of information.

Type of Review: New Collection.

Affected Public: Individuals and Households, Businesses and

Organizations, State, Local or Tribal Government.

Respondents: 2,000.

Annual responses: 2,000.

Frequency of Response: Once per request.

Average minutes per response: 15.

Burden hours: 500.

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 Office of Management and Budget Control Number.

Dated: June 12, 2014.

Amy Borgstrom,

Associate Director of Policy.

[FR Doc. 2014–14225 Filed 6–17–14; 8:45 am]

BILLING CODE 6050–28–P

DEPARTMENT OF DEFENSE

Office of the Secretary

Renewal of Department of Defense Federal Advisory Committees

AGENCY: DoD.

ACTION: Renewal of Federal Advisory Committee.

SUMMARY: The Department of Defense is publishing this notice to announce that it is renewing the charter for the Missouri River (North Dakota) Task Force (''the Task Force'').

FOR FURTHER INFORMATION CONTACT: Jim Freeman, Advisory Committee Management Officer for the Department of Defense, 703–692–5952.

SUPPLEMENTARY INFORMATION: This committee's charter is being renewed under the provisions of the Federal Advisory Committee Act of 1972 (5 U.S.C. Appendix, as amended), the Government in the Sunshine Act of 1976 (5 U.S.C. 552b) (''the Sunshine Act''), and 41 CFR 102–3.50(d).

The Task Force is a nondiscretionary Federal advisory committee that shall provide independent advice and recommendations to the Secretary of the Army on plans and projects to reduce siltation of the Missouri River in the State of North Dakota and to meet the objectives of the Pick-Sloan Program. Specifically, the Task Force shall:

a. Prepare and approve, by a majority of the members, a plan for the use of the funds made available under the Missouri River Act, to promote conservation practices in the Missouri River watershed, control and remove the sediment from the Missouri River, protect recreation on the Missouri River from sedimentation, protect Indian and non-Indian historical and cultural sites along the Missouri River from erosion, and control erosion along the Missouri River;

b. Develop and recommend to the Secretary of the Army for implementation critical restoration projects meeting the goals of the plan; and

c. Determine if these projects primarily benefit the Federal Government.

The Task Force may, on an annual basis, revise the plan and shall provide the public with the opportunity to review and comment on any proposed revision.

The Task Force shall report to the Secretary of the Army and the U.S. Army Corps of Engineers.

The Secretary of the Army may act upon the Task Force's advice and recommendations.

The Department of Defense (DoD), through the Secretary of the Army, the Assistant Secretary of the Army for Civil Works, and the U.S. Army Corps of Engineers, shall provide support, as deemed necessary, for the performance of the Task Force's functions, and shall ensure compliance with the requirements of the FACA, the Government in the Sunshine Act of 1976 (5 U.S.C. 552b, as amended) (''the Sunshine Act''), governing Federal statutes and regulations, and established DoD policies and procedures.

Pursuant to Section 704 and 705 of the Missouri River Protection and Improvement Act of 2000 (''the Missouri River Act'') (Title VII of Pub. L. 106–541, the Water Resources Development Act of 2000), the Task Force shall be composed of not more than 20 members. Specifically, the Task Force membership shall be composed of:

a. The Secretary of the Army or designee, who shall serve as the Chair;

b. The Secretary of Agriculture or designee;

c. The Secretary of Energy or designee;

d. The Secretary of the Interior or designee; and

e. The Trust, which is composed of 16 members to be appointed by the Secretary of the Army, including:

i. Twelve members recommended by the Governor of North Dakota that represent, equally, the various interests of the public and include representatives of:

a. the North Dakota Department of Health,

b. the North Dakota Department of Parks and Recreation,

c. the North Dakota Department of Game and Fish,

d. the North Dakota State Water Commission,

e. the North Dakota Indian Affairs Commission,

f. agricultural groups,

g. environmental or conservation organizations,

h. the hydroelectric power industry,

i. recreations user groups,

j. local governments,

k. and other appropriate interests.

ii. Four members representing each of the four Indian tribes in the State of North Dakota. The members of the Trust shall be appointed by the Secretary of the Army as representative members to the Task Force, pursuant to 41 CFR 102–3.130(a). Those individuals who are full-time or permanent part-time Federal employees shall be appointed regular government employee (RGE) members, pursuant to 41 CFR 102–3.130(a).

All representative members of the Trust shall be appointed for a two-year term of service; and no member, unless authorized by the Secretary of Defense upon request of the Secretary of the Army, may serve more than two consecutive terms of service. In addition, all Task Force members shall, with the exception of reimbursement of official Task Force-related travel and per diem, serve without compensation.

The Department, when necessary and consistent with the Task Force's mission and DoD policies and procedures, may establish subcommittees, task forces, or working groups to support the Task Force. Establishment of subcommittees will be based upon a written determination, to include terms of reference, by the Secretary of Defense, the Deputy Secretary of Defense, or the Secretary of the Army, as the Task Force's Sponsor.

Such subcommittees shall not work independently of the chartered Task Force and shall report all of their recommendations and advice solely to the Task Force for full and open deliberation and discussion. Subcommittees, task forces, or working groups have no authority to make decisions and recommendations, verbally or in writing, on behalf of the Task Force. No subcommittee or any of its members can update or report, verbally or in writing, on behalf of the Task Force, directly to the DoD or any Federal officers or employees.

The Secretary of Defense or the Deputy Secretary of Defense may approve the appointment of subcommittee members for a two-year term of service with annual renewals; however, no member, unless authorized by the Secretary of Defense, may serve more than two consecutive terms of service. These individuals may come from the Task Force or may be new nominees, as recommended by the

Secretary of the Army and based upon the subject matters under consideration.

Subcommittee members, if not full-time or permanent part-time Federal employees, shall be appointed as experts or consultants, pursuant to 5 U.S.C. 3109, to serve as special government employee members. Those individuals who are full-time or permanent part-time Federal employees will be appointed, pursuant to 41 CFR 102–3.130(a), to serve as RGE members.

With the exception of reimbursement for official Task Force-related travel and per diem, subcommittee members shall serve without compensation.

All subcommittees operate under the provisions of FACA, the Sunshine Act, governing Federal statutes and regulations, and established DoD policies and procedures.

The Designated Federal Officer (DFO), pursuant to DoD policy, shall be a full-time or permanent part-time DoD employee, and shall be appointed in accordance with established DoD policies and procedures.

In addition, the DFO is required to be in attendance at all meetings of the Task Force and any subcommittees, for the entire duration of each and every meeting; however, in the absence of the DFO, a properly approved Alternate DFO, duly appointed to the Task Force according to established DoD policies and procedures, shall attend the entire duration of all meetings of the Task Force or its subcommittees.

The DFO or the Alternate DFO, shall call all meetings of the Task Force and its subcommittees; prepare and approve all meeting agendas; and adjourn any meeting when the DFO, or the Alternate DFO, determines adjournment to be in the public interest or required by governing regulations or DoD policies and procedures.

Pursuant to 41 CFR 102–3.105(j) and 102–3.140, the public or interested organizations may submit written statements to Missouri River (North Dakota) Task Force membership about the Task Force's mission and functions. Written statements may be submitted at any time or in response to the stated agenda of planned meeting of Missouri River (North Dakota) Task Force.

All written statements shall be submitted to the DFO for the Missouri River (North Dakota) Task Force, and this individual will ensure that the written statements are provided to the membership for their consideration. Contact information for the Missouri River (North Dakota) Task Force DFO can be obtained from the GSA's FACA Database—*http://www.facadatabase.gov/.* The DFO, pursuant to 41 CFR 102–3.150, will announce planned meetings of the Missouri River (North Dakota) Task Force. The DFO, at that time, may provide additional guidance on the submission of written statements that are in response to the stated agenda for the planned meeting in question.

Dated: June 12, 2014.

Aaron Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2014–14165 Filed 6–17–14; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF DEFENSE

Office of the Secretary

Defense Health Agency Evaluation of Non-United States Food and Drug Administration; Approved Laboratory Developed Tests Demonstration Project

AGENCY: Department of Defense.

ACTION: Notice of Demonstration.

SUMMARY: This notice is to advise interested parties of a Military Health System (MHS) demonstration project under the authority of Title 10, United States Code, Section 1092, entitled Defense Health Agency (DHA) Evaluation of Non-United States Food and Drug Administration (FDA) Approved Laboratory Developed Tests (LDTs) Demonstration Project. The demonstration project is intended to further evaluate whether it is feasible for the Department of Defense (DoD) to review LDTs not yet examined by the FDA to determine if they meet TRICARE's requirements for safety and effectiveness according to the hierarchy of reliable evidence (32 CFR 199.4(g)(15)(i)(C) and 32 CFR 199.2(b)), or TRICARE's rare disease policy (32 CFR 199.4(g)(15)(ii)) in the case of LDTs used in the diagnosis or medical management of a rare disease (32 CFR 199.2(b)), and allow those that do to be covered as a benefit under the TRICARE Program. The demonstration project will evaluate feasible alternatives to support modifications to 32 CFR 199.4(g)(15)(i)(A) to allow coverage for non-FDA approved LDTs that otherwise meet the TRICARE requirements for safety and effectiveness. The Department currently has an ongoing demonstration project to test this same provision for LDTs with a Center for Medicare and Medicaid Services (CMS) national or local coverage determination that were submitted by laboratories for consideration for coverage under TRICARE. However, this new demonstration is being conducted in order to be able to evaluate the feasibility of establishing a cost-effective and efficient way to review an expanded pool of non-FDA approved LDTs prioritized based on their potential high utilization and clinical utility within the TRICARE population. This new demonstration project will also extend coverage for prenatal and preconception cystic fibrosis carrier screening, when provided in accordance with the American College of Obstetricians and Gynecologists guidelines in order to allow DoD to establish whether there is a benefit to offering such testing to TRICARE beneficiaries.

DATES: This demonstration will be effective July 18, 2014. This demonstration will remain in effect for three years.

ADDRESSES: Defense Health Agency, Attn: Clinical Support Division, 7700 Arlington Blvd., Falls Church, VA 22040.

FOR FURTHER INFORMATION CONTACT: Jim Black, Clinical Support Division, Defense Health Agency, Telephone (703) 681–0068.

SUPPLEMENTARY INFORMATION:

A. Background

1. LDTs

According to 32 CFR 199.4(g)(15)(i)(A), TRICARE may not cost-share medical devices including LDTs if the tests are non-FDA cleared or approved; that is, they have not received FDA medical device 510(k) clearance or premarket approval. For purposes of this demonstration, LDTs that are not FDA cleared or approved will hereinafter be referred to as non-FDA approved for brevity purposes. Under the current regulation cited above, LDTs that have been identified as non-FDA approved are summarily denied.

An LDT is an in vitro diagnostic (IVD) that is designed, manufactured, and used within a single laboratory. In the past, these tests were relatively simple tests used within a single laboratory, usually at a local large hospital or academic medical center, to diagnose rare diseases or for other uses to meet the needs of a local patient population. The FDA has exercised enforcement discretion in that the agency has generally not enforced applicable provisions under the Federal Food, Drug, and Cosmetic Act (FFDCA) and its regulations with respect to LDTs.

The 1976 Medical Device Amendments modified the FFDCA to provide for a comprehensive system for the regulation of medical devices. The term ''device'' is defined broadly in 21 U.S.C. 321(h) to include: ''an

instrument, apparatus, implement, machine, contrivance, implant, in vitro reagent, or other similar or related article, including any component, part or accessory, which is * * * intended for use in the diagnosis of disease or other conditions, or in the cure, mitigation, treatment, or prevention of disease.'' Medical devices include IVDs.

FDA regulations in 21 CFR 809.3 define ''in vitro diagnostic products'' as: ''those reagents, instruments, and systems intended for use in diagnosis of disease or other conditions, including a determination of the state of health, in order to cure, mitigate, treat, or prevent disease or its sequelae. Such products are intended for use in the collection, preparation, and examination of specimens taken from the human body.'' As explained above, LDTs are a subset of IVDs. The FDA has stated that clinical laboratories that develop LDTs are acting as manufacturers of medical devices and are subject to FDA jurisdiction under the FFDCA. As noted, the FDA has chosen to exercise its ''enforcement discretion'' over many LDTs and these tests are routinely sold without FDA approval.

The Analyte Specific Reagents (ASRs) rule was published in 1997 (21 CFR 864.4020), classifying most ASRs (ASRs are considered to be the ''active ingredients'' of tests) as Class I devices. The intent was to ensure the quality of the test components and to continue enforcement discretion for LDTs.

During the 2000s, LDTs became more complex at an increasingly fast pace. In response, the FDA issued draft guidance in 2007 relating to In Vitro Diagnostic Multivariate Index Assays, a particularly complex category of tests. Final guidance has yet to be published. In July 2010, the FDA held a public meeting to discuss the agency's oversight of LDTs. In announcing the public meeting, the FDA explained:

> At the same time as LDTs are becoming more complex, diagnostic tests are playing an increasingly important role in clinical decision making and disease management, particularly in the context of personalized medicine. However, LDTs that have not been properly validated for their intended use put patients at risk. Risks include missed diagnosis, wrong diagnosis, and failure to receive appropriate treatment. . . . [and] some diagnostics critical for patient care may not be developed in a manner that provides a reasonable assurance of safety and effectiveness.

(75 FR 34463–34464)

The FDA has continued its policy of enforcement discretion over LDTs and no new draft or final guidance on the regulation of LDTs has been issued since the enactment of the Food and Drug Administration Safety and Innovation Act (FDASIA) on July 9, 2012.

Laboratories are assessed and accredited under minimum quality standards set by CMS under the Clinical Laboratory Improvement Amendments (CLIA) of 1988. CMS regulates laboratories that use LDTs as well as FDA approved tests. Laboratories performing moderate or high complexity tests are subject to specific regulatory standards governing certification, personnel, proficiency testing, patient test management, quality assurance, quality control, and inspections. CLIA certification and periodic inspections evaluate whether the laboratory has determined the analytical validity of the tests they offer, including LDTs. Analytical validity refers to how well a test performs in the laboratory; that is, how well the test measures the properties or characteristics it is intended to measure. CLIA certification does not, however, assure a device is safe and effective for its intended use, or impose any type of postmarket surveillance or adverse event reporting requirements.

On December 27, 2011, the DoD published a notice in the **Federal Register** (76 FR 80905–80907), announcing the TRICARE Evaluation of Centers for Medicare and Medicaid Services (CMS) Approved Laboratory Developed Tests (LDTs) Demonstration Project. LDTs for this demonstration were limited to only those that had a CMS national or local coverage determination and significantly informed clinical decision making for surveillance, surgical interventions, chemotherapy, or radiation therapy for cancer. This three year demonstration will continue until it expires or is terminated via separate notice and LDTs covered under the current demonstration will continue to be covered. The demonstration project was based on interested laboratories submitting their LDTs for consideration. Limited participation from industry in the demonstration served as a constraining factor and did not provide sufficient data for the DoD to make an affirmative decision regarding the feasibility of developing a cost-effective and efficient method of reviewing non-FDA approved LDTs under TRICARE's requirements for safety and efficacy.

2. TRICARE Coverage of Cystic Fibrosis Testing

In general, the TRICARE program has been, and continues to be, a benefit program based on medical necessity. The current TRICARE maternity benefit is limited to coverage of medically necessary services and supplies associated with maternity care in accordance with 32 CFR 199.4(e)(16). Further, TRICARE covers genetic testing that is medically necessary and appropriate in the diagnosis and/or treatment of a disease and when the results of the test will influence the medical management of the individual or pregnancy. Routine genetic testing, including carrier screening, that does not influence a beneficiary's medical management is specifically excluded from TRICARE coverage.

For cystic fibrosis (CF) testing in particular, TRICARE covers CF testing when performed as part of a newborn screening panel as part of well-child care. TRICARE will also cover diagnostic genetic testing for CF when it is performed on individuals to confirm a clinical diagnosis that is already suspected. TRICARE does not, however, cover pre-conception CF carrier screening for couples planning a pregnancy, pre-implantation CF screening of embryos, or prenatal CF screening of pregnant women since the results do not assist in the medical management of the patient or pregnancy. Awareness that a fetus is at increased risk of having CF, in and of itself, does not usually change the management of labor, delivery, and the neonatal period. Additionally, newborn screening panels, which are performed shortly after birth, include tests for a number of conditions including CF, and are a TRICARE covered benefit.

Notwithstanding current TRICARE benefit limitations, the Department of Defense is aware of the widespread acceptance the American College of Obstetricians and Gynecologists (ACOG) guidelines of carrier screening for CF have received. Carrier screening for CF has been widely recognized and commonly provided as part of routine obstetric practice.

B. Demonstration Project Description

1. Review of LDTs

Consequently, the DoD will initiate a new and expanded demonstration project to test whether non-FDA approved LDTs meet TRICARE's requirements for safety and effectiveness in order to permit TRICARE cost-sharing. The demonstration project will be effective 30 days after publication in the **Federal Register** and will continue for three years from the effective date of this demonstration. The new demonstration project will evaluate the feasibility of establishing a cost-effective and efficient way to review an expanded pool of non-FDA approved LDTs. For example,

LDTs evaluated under the new demonstration are not limited to those associated with cancer and do not require a CMS national or local coverage determination. Further, consideration of specific gene testing as part of the ongoing demonstration project, discussed above, does not also prevent consideration under the new demonstration project.

Non-FDA approved LDTs will be prioritized and reviewed for analytical validity, clinical validity, and clinical utility. LDT reviews will be based on the TRICARE hierarchy of reliable evidence, as defined below, to determine whether the specific test is proven safe and effective for TRICARE cost-sharing purposes.

Reliable evidence is defined in 32 CFR 199.2(b) and includes: ''(i) Well-controlled studies of clinically meaningful endpoints, published in refereed medical literature; (ii) Published formal technology assessments; (iii) The published reports of national professional medical associations; (iv) Published national medical policy organization positions; and (v) The published reports of national expert opinion organizations.'' The definition goes on to state, ''The hierarchy of reliable evidence of proven medical effectiveness, established by (i) through (v) of this paragraph, is the order of the relative weight to be given to any particular source. With respect to clinical studies, only those reports and articles containing scientifically valid data and published in the refereed medical and scientific literature shall be considered as meeting the requirements of reliable evidence. Specifically not included in the meaning of reliable evidence are reports, articles, or statements by providers or groups of providers containing only abstracts, anecdotal evidence, or personal professional opinions. Also not included in the meaning of reliable evidence is the fact that a provider or a number of providers have elected to adopt a drug, device, or medical treatment or procedure as their personal treatment or procedure of choice or standard of practice.''

There may also be non-FDA approved LDTs reviewed under the new demonstration project for use in the diagnosis or medical management of a rare disease. In accordance with 32 CFR 199.2(b), TRICARE defines a rare disease as any disease or condition that has a prevalence of less than 200,000 persons in the United States. Due to the rare nature of the condition and lack of clinical research, the hierarchy of reliable evidence as described previously may not be met. In accordance with 32 CFR 199.4(g)(15)(ii), benefits for rare diseases are reviewed on a case-by-case basis. In reviewing proposed benefits for rare diseases under the new demonstration, consistent with TRICARE's rare disease policy, a proposed LDT for a rare disease may be reviewed for analytical validity, clinical validity, and clinical utility from any or all of the following sources to determine if the proposed LDT for a rare disease is considered safe and effective for TRICARE cost-sharing purposes: (i) Trials published in refereed medical literature; (ii) Formal technology assessments; (iii) National medical policy organization positions; (iv) National professional associations; and, (v) National expert opinion organizations.

The DoD's Laboratory Joint Working Group (LJWG) will be responsible for prioritizing and reviewing the non-FDA approved LDTs for the new demonstration. Representatives are appointed by the Assistant Secretary of Defense (Health Affairs) and are comprised of government clinical and policy professionals (DoD employees and Active Duty Service Members). Reliable evidence reviews may also be performed by a third party with the appropriate expertise and recommendations provided to the LJWG.

The LJWG will prioritize the LDTs based on their potential high utilization and high clinical utility within the TRICARE population based on existing direct and purchased care data. LDTs used for non-covered conditions or tests related to unproven treatments will not be eligible for coverage and thus will not be reviewed under the new demonstration or recommended by the LJWG. Selected LDTs will be evaluated using the hierarchy of reliable evidence or rare disease policy as outlined above. By majority vote, the LJWG will recommend approval or disapproval to the Director, DHA, or designee. Approved LDTs will be available for cost-sharing under the new demonstration.

2. LDT Coverage Decisions Under the New Demonstration

Non-FDA approved LDTs determined to meet TRICARE's requirements for safety and effectiveness according to the hierarchy of reliable evidence or rare disease policy, and otherwise meet TRICARE criteria for coverage, will be recommended to the Director, DHA, or designee, for decision for approval for cost-sharing during the new demonstration period. The effective date for coverage of specific LDTs approved under the new demonstration project will be the later of: (1) January 1, 2013; or (2) the date on which there is sufficient reliable evidence to determine that the specific LDT is proven safe and effective for TRICARE cost-sharing purposes. LDTs that have been approved by the Director, DHA, or designee, under the new demonstration, as well as LDTs that have been evaluated under the new demonstration and found to lack sufficient reliable evidence of safety and efficacy and thus remain excluded from coverage, will be appropriately documented in the TRICARE Operations Manual (TOM) following existing processes. Additional information on payment methodologies will be included in the operational procedures for the new demonstration and will be published in the TOM found at *http://manuals.tricare.osd.mil/*.

Decisions regarding which LDTs are reviewed under the new demonstration, including the priority of review, are not appealable. Additionally, in order to dedicate maximum resources to the review of LDTs under the new demonstration, no formal appeal rights will be extended for tests that are reviewed under the new demonstration and found to lack sufficient reliable evidence of safety and efficacy. Should the new demonstration project be deemed successful and permanent regulatory authority enacted, appeal rights will be available as provided in 32 CFR 199.10.

3. Coverage of CF Carrier Screening Under the Demonstration

This new demonstration project will also extend coverage for prenatal and preconception CF carrier screening, when provided in accordance with the ACOG guidelines. This demonstration project will allow DoD to establish whether there is a benefit to offering such testing for purposes of determining whether to permanently establish coverage as part of the family planning genetic testing benefit at 32 CFR 199.4(e)(3)(ii), the maternity benefit at 32 CFR 199.4(e)(16), or otherwise as a special benefit. By extending coverage for CF carrier screening in accordance with ACOG guidelines under this demonstration project DoD will be able to gather the necessary data to evaluate whether there is a benefit to offering such screening, including evaluating the impact on follow-on care that a patient is given based on testing results and any other identified benefits of the testing. The Director, DHA (or designee) shall issue guidelines for collection of data involving individual cases of CF carrier screening covered under this demonstration as necessary for evaluation of the benefits resulting from

such screening. This demonstration project will extend coverage for this testing from January 1, 2013 through the end of the demonstration in order to obtain sufficient data to be able to conduct a cost benefit analysis of providing this screening for our beneficiary population.

D. Implementation

The new demonstration is effective 30 days after publication in the **Federal Register** and will continue for a period of three years from the date of the original demonstration unless terminated earlier by the Director, DHA. LDTs approved by the Director, DHA, or designee, during the new demonstration period will become available for cost-sharing for qualified TRICARE beneficiaries during the demonstration period when performed by CLIA certified laboratories. Should the FDA issue final guidance on LDTs and/or enforce the requirement for clearance or premarket approval for LDTs, the Director, DHA will modify or terminate the demonstration, as appropriate, and the DoD will ensure compliance with applicable federal law and regulations.

E. Evaluation

An annual evaluation of the new demonstration will be conducted to determine how many TRICARE approved LDTs were provided to beneficiaries across all TRICARE Regions. The evaluation will also include a review of the LDT examination and recommendation process to assess feasibility, resource requirements, and cost-effectiveness of DHA establishing an internal safety and efficacy review process for these devices for TRICARE cost-sharing purposes. These results of the evaluation will provide an evaluation of the potential improvement of the quality of healthcare services for beneficiaries who would not otherwise have access to these safe and effective tests. Based on the results of the demonstration evaluation, a recommendation will be made on whether to modify 32 CFR 199.4(g)(15)(i)(A) to remove the restriction for non-FDA approved LDTs and permit TRICARE cost-sharing of LDTs that are found to otherwise meet TRICARE requirements for safety and effectiveness. The Department of Defense will also conduct a cost benefit analysis of providing CF carrier screening in accordance with ACOG guidelines to the TRICARE beneficiary population for purposes of determining whether to permanently establish coverage.

Dated: June 13, 2014.

Aaron Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2014–14247 Filed 6–17–14; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF EDUCATION

[Docket No.: ED–2014–ICCD–0090]

Agency Information Collection Activities; Comment Request; Report of Infants and Toddlers Receiving Early Intervention Services and of Program Settings Where Services Are Provided in Accordance With Part C

AGENCY: Office of Special Education and Rehabilitative Services (OSERS), Department of Education (ED)

ACTION: Notice

SUMMARY: In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. chapter 3501 *et seq.*), ED is proposing an extension of an existing information collection.

DATES: Interested persons are invited to submit comments on or before August 18, 2014.

ADDRESSES: Comments submitted in response to this notice should be submitted electronically through the Federal eRulemaking Portal at *http://www.regulations.gov* by selecting Docket ID number ED–2014–ICCD–0090 or via postal mail, commercial delivery, or hand delivery. If the regulations.gov site is not available to the public for any reason, ED will temporarily accept comments at *ICDocketMgr@ed.gov.* Please note that comments submitted by fax or email and those submitted after the comment period will not be accepted; ED will ONLY accept comments during the comment period in this mailbox when the regulations.gov site is not available. Written requests for information or comments submitted by postal mail or delivery should be addressed to the Director of the Information Collection Clearance Division, U.S. Department of Education, 400 Maryland Avenue SW., LBJ, Mailstop L–OM–2–2E319, Room 2E105, Washington, DC 20202.

FOR FURTHER INFORMATION CONTACT: For specific questions related to collection activities, please contact Meredith Miceli, 202–245–6028.

SUPPLEMENTARY INFORMATION: The Department of Education (ED), 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. ED is soliciting comments on the proposed information collection request (ICR) that is described below. The Department of Education 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: Report of Infants and Toddlers Receiving Early Intervention Services and of Program Settings Where Services are Provided in Accordance with Part C.

OMB Control Number: 1820–0557.

Type of Review: Revision of a currently approved collection.

Respondents/Affected Public: State, Local, or Tribal Governments.

Total Estimated Number of Annual Responses: 56.

Total Estimated Number of Annual Burden Hours: 6,697.

Abstract: This data collection provides instructions and forms necessary for States to report the number of children receiving early intervention services under Part C of Individuals with Disabilities Education Act (IDEA), the settings in which these children are provided services, and the reasons by which these children exit Part C of IDEA. The form satisfies reporting requirements and is used by OSEP to monitor State agencies and for Congressional reporting.

Dated: June 13, 2014.

Stephanie Valentine,

Acting Director, Information Collection Clearance Division, Privacy, Information and Records Management Services, Office of Management.

[FR Doc. 2014–14262 Filed 6–17–14; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

[Docket No.: ED–2014–ICCD–0089]

Agency Information Collection Activities; Comment Request; an Impact Evaluation of the Teacher Incentive Fund (TIF)

AGENCY: Institute of Education Sciences/ National Center for Education Sciences Statistics (IES), Department of Education (ED)

ACTION: Notice.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. chapter 3501 *et seq.*), ED is proposing a revision of an existing information collection.

DATES: Interested persons are invited to submit comments on or before August 18, 2014.

ADDRESSES: Comments submitted in response to this notice should be submitted electronically through the Federal eRulemaking Portal at *http://www.regulations.gov* by selecting Docket ID number ED–2014–ICCD–0089 or via postal mail, commercial delivery, or hand delivery. If the regulations.gov site is not available to the public for any reason, ED will temporarily accept comments at *ICDocketMgr@ed.gov.* Please note that comments submitted by fax or email and those submitted after the comment period will not be accepted; ED will ONLY accept comments during the comment period in this mailbox when the regulations.gov site is not available. Written requests for information or comments submitted by postal mail or delivery should be addressed to the Director of the Information Collection Clearance Division, U.S. Department of Education, 400 Maryland Avenue SW., LBJ, Mailstop L–OM–2–2E319, Room 2E105, Washington, DC 20202.

FOR FURTHER INFORMATION CONTACT: For specific questions related to collection activities, please contact Elizabeth Warner, 202–208–7169.

SUPPLEMENTARY INFORMATION: The Department of Education (ED), 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. ED is soliciting comments on the proposed information collection request (ICR) that is described below. The Department of Education 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: An Impact Evaluation of the Teacher Incentive Fund (TIF).

OMB Control Number: 1850–0876.

Type of Review: A revision of an existing information collection.

Respondents/Affected Public: Individuals or households, State, Local, or Tribal Governments.

Total Estimated Number of Annual Responses: 3,893.

Total Estimated Number of Annual Burden Hours: 1,758.

Abstract: This is the revised submission to request approval for continued data collection activities that will be used to support An Impact Evaluation of the Teacher Incentive Fund (TIF). The evaluation will estimate the impact of the differentiated pay component of the TIF program on student achievement and teacher and principal quality and retention. In addition, the evaluation will provide descriptive information of the program's implementation, grantee challenges, and grantee responses to challenges. A total of four years of data are being collected, and thus requires approval for a final round of data collection.

Dated: June 13, 2014.

Stephanie Valentine,

Acting Director, Information Collection Clearance Division, Privacy, Information and Records Management Services, Office of Management.

[FR Doc. 2014–14263 Filed 6–17–14; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF EDUCATION

[Docket No.: ED–2014–ICCD–0091]

Agency Information Collection Activities; Comment Request; Report of Dispute Resolution Under Part C of the Individuals With Disabilities Education Act

AGENCY: Office of Special Educations and Rehabilitative Services (OSERS), Department of Education (ED).

ACTION: Notice

SUMMARY: In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. chapter 3501 *et seq.*), ED is proposing an extension of an existing information collection.

DATES: Interested persons are invited to submit comments on or before August 18, 2014.

ADDRESSES: Comments submitted in response to this notice should be submitted electronically through the Federal eRulemaking Portal at *http://www.regulations.gov* by selecting Docket ID number ED–2014–ICCD–0091 or via postal mail, commercial delivery, or hand delivery. If the regulations.gov site is not available to the public for any reason, ED will temporarily accept comments at *ICDocketMgr@ed.gov.* Please note that comments submitted by fax or email and those submitted after the comment period will not be accepted; ED will ONLY accept comments during the comment period in this mailbox when the regulations.gov site is not available. Written requests for information or comments submitted by postal mail or delivery should be addressed to the Director of the Information Collection Clearance Division, U.S. Department of Education, 400 Maryland Avenue SW., LBJ, Mailstop L–OM–2–2E319, Room 2E105, Washington, DC 20202.

FOR FURTHER INFORMATION CONTACT: For specific questions related to collection activities, please contact Meredith Miceli, 202–245–6028.

SUPPLEMENTARY INFORMATION: The Department of Education (ED), 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. ED is

soliciting comments on the proposed information collection request (ICR) that is described below. The Department of Education 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: Report of Dispute Resolution Under Part C of the Individuals with Disabilities Education Act.

OMB Control Number: 1820–0678.

Type of Review: An extension of an existing information collection.

Respondents/Affected Public: State, Local, or Tribal Governments.

Total Estimated Number of Annual Responses: 56.

Total Estimated Number of Annual Burden Hours: 3,360.

Abstract: This data collection provides instructions and forms necessary for States to report the number of written, signed complaints; mediation requests; and hearing requests and the status of these actions with regards to children served under Part C of Individuals with Disabilities Education Act (IDEA) initiated during the reporting year. The form satisfies reporting requirements and is used by OSEP to monitor SEAs and for Congressional reporting.

Dated: June 13, 2014.

Stephanie Valentine,

Acting Director, Information Collection Clearance Division, Privacy, Information and Records Management Services, Office of Management.

[FR Doc. 2014–14261 Filed 6–17–14; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Sunshine Act Meeting Notice

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. 94–409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING: Federal Energy Regulatory Commission.

DATE AND TIME: June 19, 2014, 10:00 a.m.

PLACE: Room 2C, 888 First Street NE., Washington, DC 20426.

STATUS: Open.

MATTERS TO BE CONSIDERED: Agenda

* NOTE—Items listed on the agenda may be deleted without further notice.

CONTACT PERSON FOR MORE INFORMATION: Kimberly D. Bose, Secretary, Telephone (202) 502–8400.

For a recorded message listing items struck from or added to the meeting, call (202) 502–8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's Web site at *http://www.ferc.gov* using the eLibrary link, or may be examined in the Commission's Public Reference Room.

1006TH—MEETING; REGULAR MEETING

[June 19, 2014; 10:00 a.m.]

Item No.	Docket No.	Company
	Administrative	
A–1	AD02–1–000	Agency Business Matters.
A–2	AD02–7–000.	Customer Matters, Reliability, Security and Market Operations.
A–3	AD14–14–000.	Price Formation in Energy and Ancillary Services. Markets Operated by Regional Transmission. Organizations and Independent System Operators.
	Electric	
E–1	OMITTED.	
E–2	OMITTED.	
E–3	ER13–83–003	Duke Energy Carolinas, LLC and Duke Energy Progress, Inc.
	ER13–83–004.	
	ER13–83–005.	
	ER13–897–001	Louisville Gas and Electric Company and Kentucky Utilities Company.
	ER13–897–002.	
	ER13–908–001	Alabama Power Company.
	ER13–908–002.	
	ER13–913–001	Ohio Valley Electric Corporation.
	ER13–913–002.	
E–4	ER14–1386–000	California Independent System Operator Corporation.
E–5	ER14–1578–000	PacifiCorp.
E–6	RM14–14–000	Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities.

1006TH—MEETING; REGULAR MEETING—Continued

[June 19, 2014; 10:00 a.m.]

Item No.	Docket No.	Company
E–7	EL11–66–001	Martha Coakley, Massachusetts Attorney General; Conneticut Public Utilities Regulatory Authority; Massachusetts Department of Public Utilities; New Hampshire Public Utilities Commission; Connecticut Office of Consumer Counsel; Maine Office of the Public Advocate; George Jepsen, Connecticut Attorney General; New Hampshire Office of Consumer Advocate; Rhode Island Division of Public Utilities and Carriers; Vermont Department of Public Service; Massachusetts Municipal Wholesale Electric Company; Associated Industries of Massachusetts; The Energy Consortium; Power Options, Inc.; and the Industrial Energy Consumer Group v. Bangor Hydro-Electric Company; Central Maine Power Company; New England Power Company d/b/a National Grid; New Hampshire Transmission LLC d/b/a NextEra; NSTAR Electric and Gas Corporation; Northeast Utilities Service Company; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; Vermont Transco, LLC.
E–8	EL13–33–000	ENE (Environment Northeast), The Greater Boston Real Estate Board, National Consumer Law Center, and NEPOOL Industrial Customer Coalition v. Bangor Hydro-Electric Company, Central Maine Power Company, New England Power Company, New Hampshire Transmission LLC, NSTAR Electric Company, Northeast Utilities Service Company, The United Illuminating Company, Unitil Energy Systems, Inc., Fitchburg Gas and Electric Light Company, and Vermont Transco, LLC.
E–9	EL12–39–000	Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency v. Florida Power Corporation.
E–10	EL13–63–000	Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency v. Duke Energy Florida, Inc.
	EL12–39–000	Seminole Electric Cooperative, Inc. and Florida Municipal Power Agency v. Florida Power Corporation.
E–11	EL12–59–000	Golden Spread Electric Cooperative, Inc. v. Southwestern Public Service Company.
E–12	EL13–78–000 EL12–59–000.	Golden Spread Electric Cooperative, Inc. v. Southwestern Public Service Company.
E–13	OMITTED.	
E–14	OMITTED.	
E–15	OMITTED.	
E–16	EL13–86–000	Grand Valley Rural Power Lines, Holy Cross Electric Association, Inc., Intermountain Rural Electric Association, Inc. and Yampa Valley Electric Association, Inc. v. Public Service Company of Colorado.
E–17	RM14–7–000	Modeling, Data, and Analysis Reliability Standards.
E–18	RM14–1–000	Reliability Standard for Geomagnetic Disturbance Operations.
E–19	RD14–7–000	North American Electric Reliability Corporation.
E–20	ER14–1626–000	Constellation NewEnergy, Inc.
	ER14–1627–000	Constellation Energy Commodities Group Maine, LLC.
	ER14–1625–000	Exelon Generation Company, LLC.
E–21	ER13–1748–000 ER13–1748–001.	Southwest Power Pool, Inc.
E–22	ER12–1179–018 ER13–1173–000.	Southwest Power Pool, Inc.
E–23	ER13–2452–001	California Independent System Operator Corporation.
E–24	ER08–375–006	Southern California Edison Company.
E–25	AC11–46–000	Ameren Corporation.
E–26	AC11–46–002 AC11–46–003.	Ameren Corporation.
	Miscellaneous	
M–1	RM13–17–001	Communication of Operational Information Between Natural Gas Pipelines and Transmission Operators.
	Gas	
G–1	RP14–380–000	National Fuel Gas Supply Corporation and Empire Pipeline, Inc.
G–2	RP14–453–000	Enable Gas Transmission, LLC and Enable Mississippi River Transmission, LLC.
	Hydro	
H–1	P–12690–008 P–12690–007. EL14–47–000.	Public Utility District No. 1 of Snohomish County, Washington.
H–2	P–2082–058	PacifiCorp.
H–3	P–14589–000	Green Energy Storage Corp.
H–4	P–12756–004	BOST3 Hydroelectric LLC.
H–5	P–12714–004	H20 Holdings, LLC.
H–6	P–13579–003	FFP Qualified Hydro 14, LLC.
	P–14491–001	Western Minnesota Municipal Power Agency.

1006TH—MEETING; REGULAR MEETING—Continued

[June 19, 2014; 10:00 a.m.]

Item No.	Docket No.	Company
H–7	P–13123–002	Eagle Crest Energy Company.
	Certificates	
C–1	CP13–25–000	Cameron LNG, LLC.
	CP13–27–000	Cameron Interstate Pipeline, LLC.
C–2	CP13–545–001	Dominion Transmission, Inc. and Tennessee Gas Pipeline Company, L.L.C.
C–3	CP13–516–000	EcoEléctrica, L.P.

Issued: June 12, 2014.

Kimberly D. Bose,

Secretary.

A free webcast of this event is available through *www.ferc.gov.* 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 event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit *www.CapitolConnection.org* or contact Danelle Springer or David Reininger at 703–993–3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

[FR Doc. 2014–14370 Filed 6–16–14; 4:15 pm]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–RCRA–2014–0296, FRL–9912–49–OSWER]

Agency Information Collection Activities; Proposed Collection; Comment Request; 2015 Hazardous Waste Report, Notification of Regulated Waste Activity, and Part A Hazardous Waste Permit Application and Modification

AGENCY: Environmental Protection Agency.

ACTION: Notice.

SUMMARY: The Environmental Protection Agency (EPA) is planning to submit an information collection request (ICR), 2015 Hazardous Waste Report, Notification of Regulated Waste Activity, and Part A Hazardous Waste Permit Application and Modification (EPA ICR No. 0976. 17, OMB Control No. 2050–0024) to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*). Before doing so, EPA is soliciting public comments on specific aspects of the proposed information collection as described below. This is a proposed extension of the ICR, which is currently approved through December 31, 2014. An Agency may not conduct or sponsor and a person is not required to respond to a collection of information unless it displays a currently valid OMB control number.

DATES: Comments must be submitted on or before August 18, 2014.

ADDRESSES: Submit your comments, referencing by Docket ID No. EPA–HQ–RCRA–2014–0296, online using *www.regulations.gov* (our preferred method), by email to *rcra-docket@epa.gov,* or by mail to: EPA Docket Center, Environmental Protection Agency, Mail Code 28221T, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

EPA's policy is that all comments received will be included in the public docket without change including any personal information provided, unless the comment includes profanity, threats, information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute.

FOR FURTHER INFORMATION CONTACT: Peggy Vyas, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: 703–308–5477; fax number: 703–308–8433; email address: *vyas.peggy@epa.gov.*

SUPPLEMENTARY INFORMATION: Supporting documents which explain in detail the information that the EPA will be collecting are available in the public docket for this ICR. The docket can be viewed online at *www.regulations.gov* or in person at the EPA Docket Center, EPA West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The telephone number for the Docket Center is 202–566–1744. For additional information about EPA's public docket, visit *http://www.epa.gov/dockets.*

Pursuant to section 3506(c)(2)(A) of the PRA, EPA is soliciting comments and information to enable it to: (i) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility; (ii) evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (iii) enhance the quality, utility, and clarity of the information to be collected; and (iv) minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses. EPA will consider the comments received and amend the ICR as appropriate. The final ICR package will then be submitted to OMB for review and approval. At that time, EPA will issue another **Federal Register** notice to announce the submission of the ICR to OMB and the opportunity to submit additional comments to OMB.

Abstract: Section 3002 of RCRA requires hazardous waste generators to report, at least every 2 years, the quantity and nature of hazardous waste generated and managed each year. Section 3004 requires treatment, storage, and disposal facilities (TSDFs) to report any waste received. This is mandatory reporting. The information is collected via the Hazardous Waste Report (EPA Form 8700–13 A/B). This form is also known as the ''Biennial Report'' form.

Section 3010 of RCRA requires any person who generates or transports regulated waste or who owns or operates a facility for the treatment, storage, or disposal of regulated waste to notify the EPA of their activities, including the location and general description of activities and the regulated wastes handled. The entity is then issued an EPA Identification number. Entities use the Notification Form (EPA Form 8700–12) to notify EPA of their hazardous waste activities. This form is also known as the ''Notification'' form.

Section 3005 of RCRA requires TSDFs to obtain a permit. To obtain the permit, the TSDF must submit an application describing the facility's operation. The RCRA Hazardous Waste Part A Permit Application form (EPA Form 8700–23) defines the processes to be used for treatment, storage, and disposal of hazardous wastes; the design capacity of such processes; and the specific hazardous wastes to be handled at the facility. This form is also known as the ''Part A'' form.

Form Numbers: 8700–12, 8700–13A/B, and 8700–23.

Respondents/affected entities: Business or other for-profit as well as State, Local, or Tribal governments.

Respondent's obligation to respond: mandatory (RCRA Sections 3002, 3304, 3005, 3010).

Estimated number of respondents: 56,800.

Frequency of response: biennially.

Total estimated burden: 432,903 hours. Burden is defined at 5 CFR 1320.03(b).

Total estimated cost: $18,404,964 (per year), includes $18,153,496 annualized labor and $251,468 annualized capital or operation & maintenance costs.

Changes in Estimates: The burden hours are likely to stay substantially the same.

Dated: June 11, 2014.

Cheryl Coleman,

Acting Director, Office of Resource Conservation and Recovery.

[FR Doc. 2014–14248 Filed 6–17–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL 9912–46–OAR]

Office of Research and Development; Ambient Air Monitoring Reference and Equivalent Methods: Designation of Four New Equivalent Methods

AGENCY: Environmental Protection Agency.

ACTION: Notice of the designation of four new equivalent methods for monitoring ambient air quality.

SUMMARY: Notice is hereby given that the Environmental Protection Agency (EPA) has designated, in accordance with 40 CFR part 53, four new equivalent methods: One for measuring concentrations of nitrogen dioxide (NO_2), two for measuring ozone (O_3) and one for measuring concentrations of lead (Pb), in the ambient air.

FOR FURTHER INFORMATION CONTACT: Robert Vanderpool, Human Exposure and Atmospheric Sciences Division (MD–D205–03), National Exposure Research Laboratory, U.S. EPA, Research Triangle Park, North Carolina 27711. Email: *Vanderpool.Robert@epa.gov.*

SUPPLEMENTARY INFORMATION: In accordance with regulations at 40 CFR part 53, the EPA evaluates various methods for monitoring the concentrations of those ambient air pollutants for which EPA has established National Ambient Air Quality Standards (NAAQSs) as set forth in 40 CFR part 50. Monitoring methods that are determined to meet specific requirements for adequacy are designated by the EPA as either reference methods or equivalent methods (as applicable), thereby permitting their use under 40 CFR part 58 by States and other agencies for determining compliance with the NAAQSs.

The EPA hereby announces the designation of one new equivalent method for measuring nitrogen dioxide (NO_2), two equivalent methods for measuring ozone (O_3) and one equivalent method for measuring concentrations of lead (Pb)in the ambient air. These designations are made under the provisions of 40 CFR part 53, as amended on August 31, 2011 (76 FR 54326–54341).

The new equivalent method for NO_2 is an automated method (analyzer) utilizing the principle of Cavity Attenuated Phase Shift spectroscopy and the calibration procedure specified in the operation manual. The newly designated equivalent method is identified as follows:

EQNA–0514–212, ''Teledyne Advanced Pollution Instrumentation, Model T500U cavity attenuated phase shift spectroscopy Nitrogen Dioxide Analyzer'', operated on any full scale range between 0–50 ppb and 0–1000 ppb, with any range mode (Single, Dual, or AutoRange), with a sample particulate filter, at any operating temperature from 5 °C to 40 °C, with the following software setting: Temperature and Pressure compensation ON; in accordance with the associated instrument manual, and with or without any of the following options: Zero/Span valves, internal Zero/Span permeation oven (IZS), external communication and data monitoring interfaces.

One new O_3 equivalent method is an automated monitoring method (analyzer) utilizing a measurement principle based on based on non-dispersive ultraviolet absorption photometry. The newly designated equivalent method is identified as follows:

EQOA–0514–214, ''Teledyne Advanced Pollution Instrumentation, Model T204 $NO_X + O_3$ Analyzer'', operated on any full scale range between 0–100 ppb and 0–500 ppb, at any operating temperature from 5 °C to 40°C, with either a user-or vendor-supplied vacuum pump capable of providing an absolute pressure of 10 inches mercury or less at 3 slpm, in accordance with the associated instrument manual, and with or without any of the following options: Zero/Span valves, external communication and data monitoring interfaces.

The application for the equivalent method determination for the NO_2 candidate method was received by the EPA on November 4, 2013 and ozone candidate method was received by the EPA on January 7, 2014. The analyzer models are commercially available from the applicant, Teledyne Advanced Pollution Instrumentation, 9480 Carroll Park Drive, San Diego, CA 92121–2251.

A second O_3 equivalent method is an automated monitoring method (analyzer) utilizing a measurement principle based on non-dispersive ultraviolet absorption photometry. The designated equivalent method is identified as follows:

EQOA–0514–215, ''2B Technologies Model 211 Scrubberless Ozone Monitor,'' operated in a range of 0–0.5 ppm in an environment of 20–30 °C, with temperature and pressure compensation, internal DewLine for humidity control, gas phase titration of ozone for interference-free measurements, using a 1 minute average, with a 110–220V AC power adapter or a 12V DC source, 8.0 to 12.0 watt power consumption, operated according to the Model 211 Scrubberless Ozone Monitor Operation Manual with either an external nitric oxide source or internal photolytic generator for production of NO scrubber gas from nitrous oxide, and with or without the following: Cigarette lighter adapter or a 12V DC battery for portable operation, external PTFE inlet filter and holder,

serial data port with computer cable, BNC connector for 0–2.5V or 4–20 mA scalable analog output, internal data logger, microFlash card for data recording and backup, rack mount hardware, and long life sample pump.

The application for an equivalent method determination for this candidate method was received by the EPA on January 14, 2014. The analyzer models are commercially available from the applicant, 2B Technology, Inc., 2100 Central Ave., Suite 105, Boulder, CO 80303.

The new equivalent method for Pb is a manual method that uses the sampling procedure specified in the Reference Method for the Determination of Lead in Suspended Particulate Matter Collected From Ambient Air (High-Volume Sampler), 40 CFR Part 50, Appendix G, with a different extraction and analytical procedure. The method is identified as follows:

EQL–0514–213 ''*Determination of Lead (PB) on TSP Hi-Volume Filters by Microwave Assisted Digestion and Time of Flight Inductively Coupled Plasma Mass Spectrometry (TOF ICP–MS).*'' In this method, total suspended particulate matter (TSP) is collected on glass fiber filters, using the sampler and procedure of the EPA Reference Method for the Determination of Suspended Particulate Matter in the Atmosphere (High-Volume Method) (40 CFR 50, Appendix B). The TSP sample is extracted with a solution of nitric acid and digested in a microwave digestion system at 175°C for 15 minutes, centrifuged for 30 minutes at 2000 rpm, and brought to a final acid concentration of 2–3%. The lead content of the sample extract is analyzed by Time of Flight Inductively Coupled Plasma Mass Spectrometry (TOF ICP–MS), based on EPA SW–846 Method 6010C.

The application for equivalent method determination for this Pb method was submitted by South Coast Air Quality Management District, 21865 Copley Drive, Diamond Bar, CA 91765–4182 and was received by the EPA's Office of Research and Development on May 18, 2012. The method descriptions will be available at *http://www.epa.gov/ttnamti1/pb-monitoring.html.*

Test monitors representative of these methods have been tested in accordance with the applicable test procedures specified in 40 CFR part 53, as amended on August 31, 2011. After reviewing the results of those tests and other information submitted in the applications, EPA has determined, in accordance with Part 53, that these methods should be designated as equivalent methods.

As designated equivalent methods, these methods are acceptable for use by states and other air monitoring agencies under the requirements of 40 CFR part 58, Ambient Air Quality Surveillance. For such purposes, the methods must be used in strict accordance with the operation or instruction manuals associated with the methods and subject to any specifications and limitations (e.g., configuration or operational settings) specified in the applicable designated descriptions (see the identification of the methods above).

Use of the methods also should be in general accordance with the guidance and recommendations of applicable sections of the ''Quality Assurance Handbook for Air Pollution Measurement Systems, Volume I,'' EPA/600/R–94/038a and ''Quality Assurance Handbook for Air Pollution Measurement Systems, Volume II, Ambient Air Quality Monitoring Program'' EPA–454/B–08–003, December, 2008. Provisions concerning modification of such methods by users are specified under Section 2.8 (Modifications of Methods by Users) of Appendix C to 40 CFR part 58.

Consistent or repeated noncompliance should be reported to: Director, Human Exposure and Atmospheric Sciences Division (MD–E205–01), National Exposure Research Laboratory, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

Designation of these equivalent methods is intended to assist the States in establishing and operating their air quality surveillance systems under 40 CFR part 58. Questions concerning the commercial availability or technical aspects of the methods should be directed to the applicant.

Jennifer Orme-Zavaleta,

Director, National Exposure Research Laboratory.

[FR Doc. 2014–14249 Filed 6–17–14; 8:45 am]

BILLING CODE P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–9912–41–OA]

Announcement of the Board of Directors for the National Environmental Education Foundation

AGENCY: Office of External Affairs and Environmental Education, Environmental Protection Agency.

ACTION: Notice.

SUMMARY: The National Environmental Education and Training Foundation (doing business as The National Environmental Education Foundation or NEEF) was created by Section 10 of Public Law #101–619, the National Environmental Education Act of 1990. It is a private 501(c)(3) non-profit organization established to promote and support education and training as necessary tools to further environmental protection and sustainable, environmentally sound development. It provides the common ground upon which leaders from business and industry, all levels of government, public interest groups, and others can work cooperatively to expand the reach of environmental education and training programs beyond the traditional classroom. The Foundation promotes innovative environmental education and training programs such as environmental education for medical healthcare providers and broadcast meteorologists; it also develops partnerships with government and other organizations to administer projects that promote the development of an environmentally literal public. The Administrator of the U.S. Environmental Protection Agency, as required by the terms of the Act, announces the following appointment to the National Environmental Education Foundation Board of Directors. The appointee is David M. Kiser, Ph.D., Vice President, Environment, Health, Safety and Sustainability, International Paper.

FOR FURTHER INFORMATION CONTACT: For information regarding this Notice of Appointment, please contact Mr. Brian Bond, Senior Advisor to the Administrator for Public Engagement, U.S. EPA 1200 Pennsylvania Ave. NW., Washington, DC 20460. General information concerning NEEF can be found on their Web site at: *http://www.neefusa.org.*

SUPPLEMENTARY INFORMATION:

Additional Considerations: Great care has been taken to assure that this new appointee not only has the highest degree of expertise and commitment, but also brings to the Board diverse points of view relating to environmental education. This appointment is a four-year term which may be renewed once for an additional four years pending successful re-election by the NEEF nominating committee.

This appointee will join the current Board members which include:

○ Decker Anstrom (NEEF Chairman) Former U.S. Ambassador, Retired Chairman, The Weather Channel Companies.

○ Trish Silber (NEEF Vice Chair) President, Aliniad Consulting Partners, Inc.

○ Kenneth Strassner (NEEF Treasurer) Strassner Consulting, LLC.

○ Diane Wood (NEEF Secretary) President, National Environmental Education Foundation.

○ Carlos Alcazar, Founder and Chairman, Culture ONE World.

○ Megan Reilly Cayten, Co-Founder and Chief Executive Officer, Catrinka, LLC.

○ Philippe Cousteau, Co-Founder and CEO, EarthEcho International.

○ Wonya Lucas, President, Lucas Strategic Consulting.

○ Shannon Schuyler, Principal, Corporate Responsibility Leader, PricewaterhouseCoopers (PwC).

○ Bradley Smith, Ph.D., Emeritus Dean, Huxley College of the Environment, Western Washington University.

○ Jacqueline M. Thomas, Vice President of Corporate Responsibility, Toyota Motor Sales USA Inc.

Background: Section 10(a) of the National Environmental Education Act of 1990 mandates a National Environmental Education Foundation. The Foundation is established in order to extend the contribution of environmental education and training to meeting critical environmental protection needs, both in this country and internationally; to facilitate the cooperation, coordination, and contribution of public and private resources to create an environmentally advanced educational system; and to foster an open and effective partnership among Federal, State, and local government, business, industry, academic institutions, community based environmental groups, and international organizations.

The Foundation is a charitable and nonprofit corporation whose income is exempt from tax, and donations to which are tax deductible to the same extent as those organizations listed pursuant to section 501(c) of the Internal Revenue Code of 1986. The Foundation is not an agency or establishment of the United States. The purposes of the Foundation are—

(A) Subject to the limitation contained in the final sentence of subsection (d) herein, to encourage, accept, leverage, and administer private gifts for the benefit of, or in connection with, the environmental education and training activities and services of the United States Environmental Protection Agency;

(B) to conduct such other environmental education activities as will further the development of an environmentally conscious and responsible public, a well-trained and environmentally literate workforce, and an environmentally advanced educational system;

(C) to participate with foreign entities and individuals in the conduct and coordination of activities that will further opportunities for environmental education and training to address environmental issues and problems involving the United States and Canada or Mexico.

The Foundation develops, supports, and/or operates programs and projects to educate and train educational and environmental professionals, and to assist them in the development and delivery of environmental education and training programs and studies.

The Foundation has a governing Board of Directors (hereafter referred to in this section as 'the Board'), which consists of 13 directors, each of whom shall be knowledgeable or experienced in the environment, education and/or training. The Board oversees the activities of the Foundation and assures that the activities of the Foundation are consistent with the environmental and education goals and policies of the Environmental Protection Agency and with the intents and purposes of the Act. The membership of the Board, to the extent practicable, represents diverse points of view relating to environmental education and training. Members of the Board are appointed by the Administrator of the Environmental Protection Agency.

Within 90 days of the date of the enactment of the National Environmental Education Act, and as appropriate thereafter, the Administrator will publish in the **Federal Register** an announcement of appointments of Directors of the Board. Such appointments become final and effective 90 days after publication in the **Federal Register**. The directors are appointed for terms of 4 years. The Administrator shall appoint an individual to serve as a director in the event of a vacancy on the Board within 60 days of said vacancy in the manner in which the original appointment was made. No individual may serve more than 2 consecutive terms as a director.

Dated: June 5, 2014.

Gina McCarthy,

Administrator.

David M. Kiser, Ph.D.

Dr. Kiser is currently Vice President, Environment, Health, Safety and Sustainability for International Paper, a leading natural resources company that values environmental education, environmental stewardship and sustainability. Dr. Kiser has over 30 years of experience as a leader in corporate sustainability and social responsibility issues, having previously served in various capacities, including EHS Vice President for Eastman Kodak Company over a 29 year career with that firm. He is very well respected among his peers for his experience leading health, safety and environmental functions, for his abilities to help organizations manage change, and for his skills in motivating and managing people.

Dr. Kiser has a Ph.D. and a Masters in Physiology from Penn State and a Bachelor's Degree in Education from Western Michigan University. He has served as an instructor at Rochester Institute of Technology in that school's MBA program and is also a member of a wide variety of non-profit boards including The Nature Conservancy. In addition, Dr. Kiser started his career as a high school science and math teacher in Cedar Springs, Michigan.

[FR Doc. 2014–14241 Filed 6–17–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2014–0419; FRL–9911–49]

Propazine; Receipt of Application for Emergency Exemption, Solicitation of Public Comment

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: EPA has received a specific exemption request from the Texas Department of Agriculture to use the pesticide propazine (CAS No. 139–40–2) to treat up to 3,000,000 acres of cotton to control glyphosate-resistant Palmer amaranth. The applicant proposes the use of a pesticide that contains the active ingredient propazine, which belongs to the triazine class of pesticides. EPA is soliciting public comment before making the decision whether or not to grant the exemption.

DATES: Comments must be received on or before July 3, 2014.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPP–2014–0419, by one of the following methods:

• *Federal eRulemaking Portal*: *http://www.regulations.gov.* Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute.

• *Mail:* OPP Docket, Environmental Protection Agency Docket Center (EPA/

DC), (28221T), 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001.

• *Hand Delivery:* To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at *http://www.epa.gov/dockets/contacts.html.* Additional instructions on commenting or visiting the docket, along with more information about dockets generally, is available at *http://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: Lois Rossi, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001; main telephone number: (703) 305–7090; email address: *RDFRNotices@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

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

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

B. What should I consider as I prepare my comments for EPA?

1. *Submitting CBI.* Do not submit this information to EPA through *www.regulations.gov* or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for preparing your comments.* When submitting comments, remember to:

i. Identify the document by docket ID number and other identifying information (subject heading, **Federal Register** date and page number).

ii. Follow directions. The Agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

iii. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

iv. Describe any assumptions and provide any technical information and/or data that you used.

v. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

vi. Provide specific examples to illustrate your concerns and suggest alternatives.

vii. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

viii. Make sure to submit your comments by the comment period deadline identified.

3. *Environmental justice.* EPA seeks to achieve environmental justice, the fair treatment and meaningful involvement of any group, including minority and/or low income populations, in the development, implementation, and enforcement of environmental laws, regulations, and policies. To help address potential environmental justice issues, the Agency seeks information on any groups or segments of the population who, as a result of their location, cultural practices, or other factors, may have atypical or disproportionately high and adverse human health impacts or environmental effects from exposure to the pesticide(s) discussed in this document, compared to the general population.

II. What action is the Agency taking?

Under section 18 of the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) (7 U.S.C. 136p), at the discretion of the EPA Administrator, a Federal or State agency may be exempted from any provision of FIFRA if the EPA Administrator determines that emergency conditions exist which require the exemption. Texas Department of Agriculture has requested the EPA Administrator to issue a specific exemption for the use of propazine on cotton to control glyphosate-resistant Palmer amaranth. Information in accordance with 40 CFR part 166 was submitted as part of this request.

As part of this request, the applicant asserts that propazine is needed to control glyphosate-resistant Palmer amaranth due to the lack of suitable alternatives and effective control practices; and significant economic losses will occur if this pest is not controlled.

The Applicant proposes to make no more than one application of Milo-Pro herbicide on up to 3,000,000 acres of cotton in Texas during the 2014 growing season. As currently proposed, the maximum amount of product to be applied would be 70,314 gallons.

This notice does not constitute a decision by EPA on the application itself. The regulations governing FIFRA section 18 require publication of a notice of receipt of an application for a specific exemption proposing the use of a pesticide that contains the active ingredient propazine, which belongs to the triazine class of pesticides. The notice provides an opportunity for public comment on the application.

The Agency will review and consider all comments received during the comment period in determining whether to issue the specific exemption requested by the Texas Department of Agriculture.

List of Subjects

Environmental protection, Pesticides and pests.

Dated: June 6, 2014.

Lois Rossi,

Director, Registration Division, Office of Pesticide Programs.

[FR Doc. 2014–14045 Filed 6–13–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–9912–54–OA]

Meetings of the Small Community Advisory Subcommittee and the Local Government Advisory Committee

AGENCY: Environmental Protection Agency.

ACTION: Announcement of Meetings.

SUMMARY: The Small Community Advisory Subcommittee (SCAS) will meet via teleconference on Thursday, July 3, 2014, 2:00 p.m.-2:30 p.m. (EDT). The Subcommittee will discuss small community issues related to EPA's Waters of the United States. This is an open meeting. Individuals or organizations wishing to address the Subcommittee meeting will be allowed a maximum of five minutes to present their point of view on issues pertaining to small communities.

The Local Government Advisory Committee (LGAC) will meet via

teleconference on Thursday, July 3, 2014, 2:30 p.m.–3:00 p.m. (EDT). The Committee meeting will focus on the Protecting America's Waters Workgroup initial recommendations on the Waters of the United States.

These are open meetings, and all interested persons are invited to participate. The Subcommittee will hear comments from the public between 2:15 p.m. and 2:30 p.m. on Thursday, July 3, 2014, and the Committee will hear comments from the public between 2:45 p.m. and 3:00 p.m. on Thursday, July 3, 2014. Individuals or organizations wishing to address the Subcommittee or the Committee will be allowed a maximum of five minutes to present their point of view. Also, written comments should be submitted electronically to *eargle.frances@epa.gov*. Please contact the Designated Federal Officer (DFO) at the number listed below to schedule a time on the agenda. Time will be allotted on a first-come first-serve basis, and the total period for comments may be extended if the number of requests for appearances requires it.

ADDRESSES: The Small Communities Advisory Subcommittee and Local Government Advisory Committee meetings will meet via teleconference. Meeting summaries will be available after the meeting online at *www.epa.gov/ocir/scas_lgac/lgac_index.htm* and can be obtained by written request to the DFO.

FOR FURTHER INFORMATION CONTACT: Local Government Advisory Committee (LGAC) and Small Communities Advisory Subcommittee (SCAS), contact Frances Eargle, Designated Federal Officer, at (202) 564–3115 or email at *eargle.frances@epa.gov*.

Information On Services For Those With Disabilities: For information on access or services for individuals with disabilities, please contact Frances Eargle at (202) 564–3115 or email at *eargle.frances@epa.gov*. To request accommodation of a disability, please request it 10 days prior to the meeting, to give EPA as much time as possible to process your request.

Dated: June 13, 2014.

Frances Eargle,

Designated Federal Officer, Local Government Advisory Committee.

[FR Doc. 2014–14235 Filed 6–17–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–9912–44–OA]

Notification of a Joint Public Meeting and Joint Teleconferences of the Chartered Science Advisory Board and Chartered Board of Scientific Counselors and a Briefing Teleconference for New SAB Members

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of meeting.

SUMMARY: The Environmental Protection Agency (EPA) Science Advisory Board (SAB) Staff Office announces a joint public meeting of the Chartered SAB and the EPA's Office of Research and Development (ORD) Chartered Board of Scientific Counselors (BOSC) to develop strategic advice on ORD's research activities, six joint SAB–BOSC public teleconference calls to prepare for the face-to-face meeting, and one public teleconference to orient new SAB members to ORD's work.

DATES: The joint SAB–BOSC public meeting will be held on Thursday, July 24, 2014 from 10:00 a.m. to 5:30 p.m. and Friday, July 25, 2014 from 8:30 a.m. to 2:00 p.m. ET. There will be six joint SAB–BOSC teleconferences, one for each ORD research program. The joint SAB–BOSC teleconferences will be held: (1) For the Human Health Risk Assessment program on July 1, 2014, from 3:00 p.m. to 4:30 p.m. Eastern Time (ET); (2) for the Air, Climate and Energy program on July 3, 2014, from 10:00 a.m. to 12:00 p.m. ET; (3) for the Chemical Safety for Sustainability program on July 3, 2014, from 1:30 p.m. to 3:30 p.m. ET; (4) for the Homeland Security program on July 7, 2014, from 9:00 a.m. to 11:00 a.m. ET; (5) for the Sustainable and Health Communities program on July 10, 2014, from 2:00 p.m. to 4:00 p.m. ET; and (6) for the Safe and Sustainable Water Resources program on July 17, 2014, from 1:00 p.m. to 3:00 p.m. ET.

The teleconference to provide an overview of ORD's mission and role for SAB members will be held on June 24, 2014, from 10:00 a.m. to 12:00 p.m. ET.

ADDRESSES: All the teleconferences will be held by teleconference only. The face-to-face meeting will be held at the Washington Marriott Georgetown, 1221 22nd Street, Washington, DC 20037.

FOR FURTHER INFORMATION CONTACT: Any member of the public who wishes further information concerning the meetings may contact Dr. Angela Nugent, Designated Federal Officer (DFO), EPA Science Advisory Board (1400R), U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue NW., Washington, DC 20460; via telephone/voice mail (202) 564–2218, fax (202) 202–565–2098; or email at *nugent.angela@epa.gov*. General information concerning the SAB can be found on the EPA Web site at *http://www.epa.gov/sab*.

SUPPLEMENTARY INFORMATION:

Background

The SAB was established pursuant to the Environmental Research, Development, and Demonstration Authorization Act (ERDDAA), codified at 42 U.S.C. 4365, to provide independent scientific and technical advice to the Administrator on the technical basis for Agency positions and regulations. The BOSC was established by the EPA to provide advice, information, and recommendations regarding the ORD research program. The SAB and BOSC are Federal Advisory Committees chartered under the Federal Advisory Committee Act (FACA), 5 U.S.C., App. 2. Pursuant to FACA and EPA policy, notice is hereby given that the chartered SAB and chartered BOSC will hold preparatory teleconferences and a joint meeting to develop advice on future directions for ORD's research programs. The SAB and BOSC will comply with the provisions of FACA and all appropriate SAB Staff Office procedural policies.

ORD research programs are structured to understand environmental problems and inform sustainable solutions to meet EPA's strategic goals. The research programs comprise six program areas: Air, Climate, and Energy; Safe and Sustainable Water Resources; Sustainable and Healthy Communities; Chemical Safety for Sustainability; Human Health Risk Assessment; and Homeland Security.

ORD requested that the SAB work jointly with the BOSC in 2011 to provide early advice on ORD strategic research directions. In response, the SAB and BOSC provided a report, *Office of Research and Development (ORD) New Strategic Research Directions: A Joint Report of the Science Advisory Board (SAB) and ORD Board of Scientific Councilors (BOSC),* EPA–SAB–12–001. After receiving this advisory report, ORD requested additional advice from the SAB and BOSC on ORD's research implementation plans, efforts to strengthen program integration and efforts to strengthen and measure innovation. In response, the SAB and BOSC provided a report, *Implementation of ORD Strategic Research Plans: A Joint Report of the*

Science Advisory Board and ORD Board of Scientific Counselors (EPA–SAB–12–012).

ORD is now requesting the SAB and BOSC to provide advice to inform the agency's development of Strategic Research Action Plans to cover the period 2016–2019. To address this request, the SAB and BOSC have planned a series of meetings: (1) A face-to-face meeting on this topic on July 24–25, 2014; (2) teleconferences devoted to each of the six ORD research so that ORD can brief SAB and BOSC members on ORD programs and so that SAB and BOSC members can discuss ORD's charge to their committees and preparations for the July 24–25, 2014 public meeting; and (3) a teleconference for ORD to provide a general background briefing on ORD's mission and role for new SAB members on June 24, 2014.

Availability of Meeting Materials

A meeting agenda and other materials for the meeting will be placed on the SAB Web site at *http://epa.gov/sab*.

Procedures for Providing Public Input

Public comment for consideration by EPA's federal advisory committees and panels has a different purpose from public comment provided to EPA program offices. Therefore, the process for submitting comments to a federal advisory committee is different from the process used to submit comments to an EPA program office.

Federal advisory committees and panels, including scientific advisory committees, provide independent advice to EPA. Members of the public can submit relevant comments for a federal advisory committee to consider as it develops advice for EPA. Interested members of the public may submit relevant written or oral information on the topic of this advisory activity, and/or the group conducting the activity, for the SAB and BOSC to consider during the advisory process. Input from the public to the SAB and BOSC will have the most impact if it provides specific scientific or technical information or analysis for them to consider or if it relates to the clarity or accuracy of the technical information. Members of the public wishing to provide comment should contact the DFO directly.

Oral Statements: In general, individuals or groups requesting to make an oral presentation at a public meeting will be limited to five minutes and individuals or groups requesting an oral presentation at a public teleconference will be limited to three minutes. Each person making an oral statement should also consider providing written comments so that the points presented orally can be expanded upon in writing. Interested parties should contact Dr. Angela Nugent, DFO, in writing (preferably via email) at the contact information noted above by July 17, 2014 to be placed on the list of public speakers for the joint SAB–BOSC public meeting. Parties interested in providing oral statements at any of the teleconferences should contact Dr. Angela Nugent seven days in advance of the scheduled teleconference. *Written Statements:* Written statements for the joint public meeting should be supplied to Dr. Angela Nugent, DFO, via email at the contact information noted above by July 17, 2014 so that the information may be made available to the Panel members for their consideration. Parties interested in providing written comment for consideration at any of the teleconferences should contact Dr. Angela Nugent seven days in advance of the scheduled teleconference.

Written statements should be supplied in one of the following electronic formats: Adobe Acrobat PDF, MS Word, MS PowerPoint, or Rich Text files in IBM–PC/Windows 98/2000/XP format. It is the SAB Staff Office general policy to post written comments on the Web page for advisory meetings or teleconferences. Submitters are requested to provide an unsigned version of each document because the SAB Staff Office does not publish documents with signatures on its Web sites. Members of the public should be aware that their personal contact information, if included in any written comments, may be posted to the SAB Web site. Copyrighted material will not be posted without explicit permission of the copyright holder.

Accessibility

For information on access or services for individuals with disabilities, please contact Dr. Nugent at the phone number or email address noted above, preferably at least ten days prior to the meeting, to give EPA as much time as possible to process your request.

Dated: June 11, 2014.

Thomas H. Brennan,

Deputy Director, EPA Science Advisory Board Staff Office.

[FR Doc. 2014–14244 Filed 6–17–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–9912–45–OA]

Notification of a Public Teleconference of the Chartered Clean Air Scientific Advisory Committee (CASAC)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: The Environmental Protection Agency (EPA) Science Advisory Board (SAB) Staff Office announces a public teleconference of the Chartered Clean Air Scientific Advisory Committee (CASAC) to conduct quality reviews of draft CASAC reports on EPA's Recommendation for an additional Federal Reference Method for Ozone and on EPA's Integrated Review Plan for the Primary National Ambient Air Quality Standard for Sulfur Dioxide.

DATES: The teleconference will be held on Wednesday, July 16, 2014 from 10:00 a.m. to 1:00 p.m. (Eastern Time).

Location: The public teleconference will be conducted by telephone only.

FOR FURTHER INFORMATION CONTACT: Any member of the public wishing to obtain information concerning the public teleconference may contact Mr. Aaron Yeow, Designated Federal Officer (DFO), via telephone at (202) 564–2050 or at *yeow.aaron@epa.gov*. General information about the CASAC, as well as any updates concerning the meeting announced in this notice, may be found on the EPA Web site at *http://www.epa.gov/casac*.

SUPPLEMENTARY INFORMATION: The CASAC was established pursuant to the Clean Air Act (CAA) Amendments of 1977, codified at 42 U.S.C. 7409(d)(2), to review air quality criteria and NAAQS and recommend any new NAAQS and revisions of existing criteria and NAAQS as may be appropriate. The CASAC shall also provide advice, information, and recommendations to the Administrator on the scientific and technical aspects of issues related to the criteria for air quality standards, research related to air quality, sources of air pollution, and of adverse effects which may result from various strategies to attain and maintain air quality standards. The CASAC is a Federal Advisory Committee chartered under the Federal Advisory Committee Act (FACA), 5 U.S.C., App. 2. Pursuant to FACA and EPA policy, notice is hereby given that the Chartered CASAC will hold a public teleconference to conduct quality reviews of draft CASAC reports on EPA's Recommendation for an Additional Federal Reference Method

for Ozone and on EPA's Integrated Review Plan for the Primary National Ambient Air Quality Standard for Sulfur Dioxide.

The CASAC quality review process ensures that all draft reports developed by CASAC panels, committees or workgroups are reviewed and approved by the Chartered CASAC before being finalized and transmitted to the EPA Administrator. These reviews are conducted in a public meeting or teleconference as required by FACA.

The EPA is proposing the addition of the Nitric Oxide (NO)-Chemiluminescence method as an additional Federal Reference Method (FRM) for ozone. The CASAC Air Monitoring and Methods Subcommittee (AMMS) reviewed the scientific and technical aspects of a draft document that supports the EPA's recommendation to add the NO-Chemiluminescence method as an FRM and developed the draft report ''Review of EPAs Recommendation for an Additional Federal Reference Method for Ozone-Nitric Oxide-Chemiluminescence''. The Chartered CASAC will conduct a quality review of this draft CASAC report. Background information about this advisory activity can be found on the CASAC Web site at *http://yosemite.epa.gov/sab/sabproduct.nsf/fedrgstr_activites/O3%20FRM%3A%20NO-Chemiluminescence?OpenDocument.*

The EPA's Integrated Review Plan for the Primary NAAQS for Sulfur Dioxide (External Review Draft—March 2014) presents the planned approach for the review of the primary (health-based) NAAQS for sulfur oxides. The CASAC Augmented for Sulfur Oxides Panel reviewed this document and developed the report ''Draft CASAC Review of the EPA's Integrated Review Plan for the Primary National Ambient Air Quality Standard for Sulfur Dioxide.'' The Chartered CASAC will conduct a quality review of this draft CASAC report. Background information about this advisory activity can be found on the CASAC Web site at *http://yosemite.epa.gov/sab/sabproduct.nsf/fedrgstr_activites/*SO_2*%20Primary%20NAAQS%20Review?OpenDocument.*

Availability of Meeting Materials: Prior to the meeting, the review documents, agenda and other materials will be accessible through the *calendar link on the blue navigation bar at http://www.epa.gov/casac/.*

Procedures for Providing Public Input: Public comment for consideration by EPA's federal advisory committees and panels has a different purpose from public comment provided to EPA program offices. Therefore, the process for submitting comments to a federal advisory committee is different from the process used to submit comments to an EPA program office.

Federal advisory committees and panels, including scientific advisory committees, provide independent advice to EPA. Members of the public can submit comments for a federal advisory committee to consider as it develops advice for EPA. Interested members of the public may submit relevant written or oral information on the topic of this advisory activity, and/or the group conducting the activity, for the CASAC to consider during the advisory process. Input from the public to the CASAC will have the most impact if it provides specific scientific or technical information or analysis for CASAC panels to consider or if it relates to the clarity or accuracy of the technical information. Members of the public wishing to provide comment should contact the DFO directly.

Oral Statements: In general, individuals or groups requesting an oral presentation on a public teleconference will be limited to three minutes. Each person making an oral statement should consider providing written comments as well as their oral statement so that the points presented orally can be expanded upon in writing. Interested parties should contact Mr. Aaron Yeow, DFO, in writing (preferably via email) at the contact information noted above by July 9, 2014 to be placed on the list of public speakers.

Written Statements: Written statements should be supplied to the DFO via email at the contact information noted above by July 9, 2014 so that the information may be made available to the Panel members for their consideration. Written statements should be supplied in one of the following electronic formats: Adobe Acrobat PDF, MS Word, MS PowerPoint, or Rich Text files in IBM–PC/Windows 98/2000/XP format. It is the SAB Staff Office general policy to post written comments on the Web page for the advisory meeting or teleconference. Submitters are requested to provide an unsigned version of each document because the SAB Staff Office does not publish documents with signatures on its Web sites. Members of the public should be aware that their personal contact information, if included in any written comments, may be posted to the CASAC Web site. Copyrighted material will not be posted without explicit permission of the copyright holder.

Accessibility: For information on access or services for individuals with disabilities, please contact Mr. Aaron Yeow at (202) 564–2050 or *yeow.aaron@epa.gov.* To request accommodation of a disability, please contact Mr. Yeow preferably at least ten days prior to each meeting to give EPA as much time as possible to process your request.

Dated: June 11, 2014.

Thomas H. Brennan,

Deputy Director, EPA Science Advisory Staff Office.

[FR Doc. 2014–14242 Filed 6–17–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPPT–2013–0677; FRL–9911–70]

Receipt of Test Data Under the Toxic Substances Control Act

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: EPA is announcing its receipt of test data submitted pursuant to a test rule issued by EPA under the Toxic Substances Control Act (TSCA). As required by TSCA, this document identifies each chemical substance and/or mixture for which test data have been received; the uses or intended uses of such chemical substance and/or mixture; and describes the nature of the test data received. Each chemical substance and/or mixture related to this announcement is identified in Unit I. under **SUPPLEMENTARY INFORMATION**.

FOR FURTHER INFORMATION CONTACT: *For technical information contact:* Kathy Calvo, Chemical Control Division (7405M), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001; telephone number: (202) 564–8089; email address: *calvo.kathy@epa.gov.*

For general information contact: The TSCA-Hotline, ABVI-Goodwill, 422 South Clinton Ave., Rochester, NY 14620; telephone number: (202) 554–1404; email address: *TSCA-Hotline@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Chemical Substances and/or Mixtures

Information about the following chemical substances and/or mixtures is provided in Unit IV.: D-gluco-heptonic acid, monosodium salt, (2.xi.)–(CAS No. 31138–65–5).

II. Authority

Section 4(d) of TSCA (15 U.S.C. 2603(d)) requires EPA to publish a notice in the **Federal Register** reporting

the receipt of test data submitted pursuant to test rules promulgated under TSCA section 4 (15 U.S.C. 2603).

III. Docket Information

A docket, identified by the docket identification (ID) number EPA–HQ–OPPT–2013–0677, has been established for this **Federal Register** document that announces the receipt of data. The test data received have been added to the docket for the TSCA section 4 test rule that required the test data. Use the document ID number provided in Unit IV. to access the test data in the docket for the related TSCA section 4 test rule.

The docket for this **Federal Register** document and the docket for each related TSCA section 4 test rule is available electronically at *http://www.regulations.gov* or in person at the Office of Pollution Prevention and Toxics Docket (OPPT Docket), Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OPPT Docket is (202) 566–0280. Please review the visitor instructions and additional information about the docket available at *http://www.epa.gov/dockets*.

IV. Test Data Received

This unit contains the information required by TSCA section 4(d) for the test data D-gluco-heptonic acid, monosodium salt, (2.xi.) (CAS No. 31138–65–5)

1. *Chemical Use(s):* Organic salt used as a chelating agent in cosmetics, dairy cleaners, bottle cleaners, food contact paper and paperboard, manufacturing, metal cleaning, kier boiling, caustic boil-off, paint stripping, boiler water additive for food processing, and as an ingredient in aluminum etchant. This chemical is also used as a sequestrant, latex stabilizer, and in intravenous pharmaceuticals.

2. *Applicable Test Rule:* Chemical testing requirements for second group of high production volume chemicals (HPV2), 40 CFR 799.5087.

3. *Test Data Received:* The following listing describes the nature of the test data received. The test data have been added to the docket for the applicable TSCA section 4 test rule and can be found by referencing the document ID numbers provided. EPA reviews of test data will be added to the same docket upon completion.

Health Effect. Combined Repeat Dose Toxicity with Reproduction/Developmental Toxicity Screening Test. The document ID number assigned to this data is EPA–HQ–OPPT–2007–0531–0790.

List of Subjects

Environmental protection, Hazardous substances, Reporting and recordkeeping requirements.

Dated: June 10, 2014.

Maria J. Doa,

Director, Chemical Control Division, Office of Pollution Prevention and Toxics.

[FR Doc. 2014–14245 Filed 6–17–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–9912–48–OAR]

Request for Nominations to the Clean Air Act Advisory Committee (CAAAC)

AGENCY: Environmental Protection Agency.

ACTION: Request for Nominations to the Clean Air Act Advisory Committee (CAAAC).

SUMMARY: The U.S. Environmental Protection Agency (EPA) invites nominations from a diverse range of qualified candidates to be considered for appointment to its Clean Air Act Advisory Committee (CAAAC). Vacancies are anticipated to be filled by February 2015.

Background: The Environmental Protection Agency (EPA) established the Clean Air Act Advisory Committee (CAAAC) on November 19, 1990, to provide independent advice and counsel to EPA on policy issues associated with implementation of the Clean Air Act of 1990. The Committee advises on economic, environmental, technical, scientific and enforcement policy issues. The programs falling under the purview of the committee include the National Ambient Air Quality Standards, emissions from vehicles and vehicle fuels, air toxic emissions, greenhouse gas emissions, operating permits and collecting fees, and other authorities. Members are appointed by the EPA Administrator for two-year terms with the possibility of reappointment to additional terms. The CAAAC usually meets two to three times annually and the average workload for the members is approximately 5 to 8 hours per month. Although we are unable to offer compensation or an honorarium for your services, you may receive travel and per diem allowances, according to applicable federal travel regulations. Additional information on these meetings, CAAAC and its Subcommittees can be found on the CAAAC Web site: *http://www.epa.gov/air/caaac/.*

EPA is seeking nominations from academia, industry, non-governmental/environmental organizations, state and local government agencies, tribal governments, unions, trade associations, utilities, and lawyers/consultants. EPA values and welcomes diversity. In an effort to obtain nominations of diverse candidates, EPA encourages nominations of women and men of all racial and ethnic groups.

The following criteria will be used to evaluate nominees:

—The background and experiences that would help members contribute to the diversity of perspectives on the committee (e.g., geographic, economic, social, cultural, educational, and other considerations
—Experience serving as an elected official;
—Experience serving as an appointed official for a state, county, city or tribe;
—Experience in working at the national level on local governments issues;
—Demonstrated experience with air quality policy issues;
—Executive management level experience with membership in broad-based networks;
—Excellent interpersonal, oral and written communication, and consensus-building skills.
—Ability to volunteer time to attend meetings 2–3 times a year, participate in teleconference meetings, attend listening sessions with the Administrator or other senior-level officials, develop policy recommendations to the Administrator, and prepare reports and advice letters.

EPA will not appoint any federally-registered lobbyists to the committee. In addition, EPA's policy is that, unless otherwise prescribed by statute, members generally are appointed to two-year terms.

Nominations: Nominations should include: A resume and a short biography describing the professional and educational qualifications of the nominee, as well as the nominee's current business address, email address, and daytime telephone number. In addition, nominees are invited to provide additional information that would be useful to EPA in considering the nominations, including a brief summary of the nominee's interest in air

policy issues; the availability of the nominee to participate as a member of this committee; how the nominee's background, skills, and experience would contribute to the diversity of the committee; and any concerns the nominee may have regarding committee membership. Interested candidates may self-nominate. All information should be sent to Jeneva Craig, Designated Federal Officer, preferably electronically, to *craig.jeneva@epa.gov.* Hard copies may also be mailed to Jeneva Craig, U.S. EPA, Office of Air and Radiation, Mail code 6103A, 1200 Pennsylvania Ave. NW., Washington, DC 20460. U.S. EPA is accepting nominations until September 1, 2014.

FOR FURTHER INFORMATION CONTACT: Please contact Jeneva Craig, Office of Air and Radiation, U.S. EPA at *craig.jeneva@epa.gov,* at (202) 564–1674, or by mail at U.S. EPA, Office of Air and Radiation (Mail code 6103 A), 1200 Pennsylvania Avenue NW., Washington, DC 20460.

Dated: June 12, 2014.

Jeneva Craig,

Designated Federal Official, Clean Air Act Advisory Committee, Office of Air and Radiation.

[FR Doc. 2014–14246 Filed 6–17–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2014–0392; FRL–9911–55]

Notice of Receipt of Requests for Amendments To Delete Uses in Certain Pesticide Registrations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In accordance with the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), EPA is issuing a notice of receipt of request for amendments by registrants to delete uses in certain pesticide registrations. FIFRA provides that a registrant of a pesticide product may at any time request that any of its pesticide registrations be amended to delete one or more uses. FIFRA further provides that, before acting on the request, EPA must publish a notice of receipt of any request in the **Federal Register**.

DATES: The deletions in Table 1 of Unit II, are effective July 18, 2014, because the registrants requested a waiver of the 180-day comment period, unless the Agency receives a written withdrawal request on or before July 18, 2014. The Agency will consider a written withdrawal request postmarked no later than July 18, 2014. The deletions in Table 2 of Unit II, are effective December 15, 2014, unless the Agency receives a written withdrawal request on or before December 15, 2014. The Agency will consider a written withdrawal request postmarked no later than December 15, 2014.

Users of these products who desire continued use on crops or sites being deleted should contact the applicable registrant in Table 1 of Unit II, before July 18, 2014, for the registrants that requested a waiver of the 180-day comment period. Users of these products who desire continued use on crops or sites being deleted should contact the applicable registrant in Table 2 of Unit II, before December 15, 2014.

ADDRESSES: Submit your withdrawal request, identified by docket identification (ID) number EPA–HQ–OPP–2014–0392, by one of the following methods:

- *Mail:* OPP Docket, Environmental Protection Agency Docket Center (EPA/DC), (28221T), 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001.
- *Hand Delivery:* To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at *http://www.epa.gov/dockets/contacts.html.*

Additional instructions on visiting the docket, along with more information about dockets generally, is available at *http://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: Christopher Green, Information Technology and Resources Management Division (7502P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001; main telephone number: (703) 347–0367; email address: *green.christopher@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

This action is directed to the public in general. Although this action may be of particular interest to persons who produce or use pesticides, the Agency has not attempted to describe all the specific entities that may be affected by this action.

B. How can I get copies of this document and other related information?

The docket for this action, identified by docket ID number EPA–HQ–OPP–2014–0392, is available either electronically through *http://www.regulations.gov* or in hard copy at the OPP Docket in the Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW., Washington, DC 20460–0001. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OPP Docket is (703) 305–5805. Please review the visitor instructions and additional information about the docket available at *http://www.epa.gov/dockets.*

II. What action is the Agency taking?

This notice announces receipt by the Agency of applications from registrants to delete uses in certain pesticide registrations. These registrations are listed in Table 1 & Table 2 of this unit by registration number, product name, active ingredient, and specific uses deleted:

TABLE 1—REQUESTS FOR AMENDMENTS TO DELETE USES IN CERTAIN PESTICIDE REGISTRATIONS

EPA registration No.	Product name	Active ingredient	Delete from label
279–9562	Iprodione Technical	Iprodione	Rice covering.
279–9564	Rovral 4 Flowable Fungicide	Iprodione	Rice covering.
279–9565	Rovral 4 Flowable Fungicide	Iprodione	Rice covering.
279–9566	Rovral WG Fungicide	Iprodione	Rice covering.
279–9567	Rovral 50 SP Fungicide	Iprodione	Rice covering.
279–9569	Rovral Brand 75WG Fungicide	Iprodione	Rice covering.

TABLE 1—REQUESTS FOR AMENDMENTS TO DELETE USES IN CERTAIN PESTICIDE REGISTRATIONS—Continued

EPA registration No.	Product name	Active ingredient	Delete from label
19713–600	Pendimethalin Technical	Pendimethalin	Alfalfa, Corn (Field, Pop, Sweet), Garlic, Onions (Dry bulb, Green, Welsh), Peanuts, Sorghum (Grain), Sugarcane & Sunflower.
67690–22	Profile 2SC Tree and Turf Growth Regulator.	Paclobutrazol	Turf in parks.
67690–56	SP5114	Paclobutrazol & Trinexapac-ethyl	Turf in parks.
80697–4	Tide Paclo 2SC	Paclobutrazol	Park turfgrass.
82534–4	Glufosinate 280 SL Herbicide	Glufosinate	Canola, Field corn, Silage corn, Soybeans, Burndown on soybeans, Corn, Cotton, & Soybean seed propagation.
83520–26	Biscayne Herbicide	Sodium bentazon	Residential uses.

Users of these products in Table 1 of this unit, who desire continued use on crops or sites being deleted should contact the applicable registrant before July 18, 2014, because the registrants requested a waiver of the 180-day comment period, to discuss withdrawal of the application for amendment. This 30-day period will also permit interested members of the public to intercede with registrants prior to the Agency's approval of the deletion.

TABLE 2—REQUESTS FOR AMENDMENTS TO DELETE USES IN CERTAIN PESTICIDE REGISTRATIONS

EPA registration no.	Product name	Active ingredient	Delete from label
279–9568	Iprodione 50.0%	Iprodione	Rice covering.
400–95	Omite Technical	Propargite	Non-bearing avocado use.

Users of these products in Table 2 of this unit, who desire continued use on crops or sites being deleted should contact the applicable registrant before December 15, 2014, to discuss withdrawal of the application for amendment. This 180-day period will also permit interested members of the public to intercede with registrants prior to the Agency's approval of the deletion.

Table 3 of this unit includes the names and addresses of record for all registrants of the products listed in Table 1 & Table 2 of this unit, in sequence by EPA company number.

TABLE 3—REGISTRANTS REQUESTING AMENDMENTS TO DELETE USES IN CERTAIN PESTICIDE REGISTRATIONS

EPA company No.	Company name and address
279	FMC Corp. Agricultural Products Group, 1735 Market Street, RM 1978, Philadelphia, PA 19103.
400	Chemtura Corporation, 199 Benson Road, Middlebury, CT 06749.
19713	Drexel Chemical Company, 1700 Channel Avenue, P.O. Box 13327, Memphis, TN 38113–0327.
67690	Sepro Corporation, 11550 N. Meridian Street., Suite 600, Carmel, IN 46032–4565.

TABLE 3—REGISTRANTS REQUESTING AMENDMENTS TO DELETE USES IN CERTAIN PESTICIDE REGISTRATIONS—Continued

EPA company No.	Company name and address
80697	Zhejiang Tide CropScience Co., Ltd., 4110 136th St. NW., Gig Harbor, WA 98332.
82534	Summit Agro North America Holding Corp., 300 Madison Avenue, Floor 4, New York, NY 10017–6288.
83520	Tacoma AG, LLC, 115 Obtuse Hill Road, Brookfield, CT 06804.

III. What is the Agency's authority for taking this action?

Section 6(f)(1) of FIFRA provides that a registrant of a pesticide product may at any time request that any of its pesticide registrations be amended to delete one or more uses. The FIFRA further provides that, before acting on the request, EPA must publish a notice of receipt of any such request in the **Federal Register**. Thereafter, the EPA Administrator may approve such a request.

IV. Procedures for Withdrawal of Request

Registrants who choose to withdraw a request for use deletion must submit the withdrawal in writing to Christopher Green using the methods in **ADDRESSES**. The Agency will consider written withdrawal requests postmarked no later than July 18, 2014, for the requests that the registrants requested to waive the 180-day comment period and not later than December 15, 2014, for the requests with a 180-day comment period.

V. Provisions for Disposition of Existing Stocks

The Agency has authorized the registrants to sell or distribute product under the previously approved labeling for a period of 18 months after approval of the revision, unless other restrictions have been imposed, as in special review actions.

List of Subjects

Environmental protection, Pesticides and pests.

Dated: May 29, 2014.

Michael Hardy,

Acting Director, Information Technology and Resources Management Division, Office of Pesticide Programs.

[FR Doc. 2014–14113 Filed 6–17–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–9912–47–OAR]

Request for Nominations for 2015 Clean Air Excellence Awards Program

AGENCY: Environmental Protection Agency (EPA).

ACTION: Request for nominations for Clean Air Excellence Awards.

SUMMARY: This notice announces the competition for the 2015 Clean Air Excellence Awards Program. The Environmental Protection Agency (EPA) established the Clean Air Excellence Awards Program in February 2000 to recognize outstanding and innovative efforts that support progress in achieving clean air.

DATES: All submissions of entries for the Clean Air Excellence Awards Program must be postmarked by September 12, 2014.

FOR FURTHER INFORMATION CONTACT: Additional information on this awards program, including the entry form, can be found on EPA's Clean Air Act Advisory Committee (CAAAC) Web site: *http://www.epa.gov/oar/cleanairawards/index.html*. Any member of the public who wants further information may contact Ms. Jeneva Craig, Designated Federal Officer (DFO), Office of Air and Radiation, U.S. EPA by telephone at (202) 564–1674 or by email at *craig.jeneva@epa.gov*.

SUPPLEMENTARY INFORMATION:

Awards Program Notice: Pursuant to 42 U.S.C. 7403(a)(1) and (2) and sections 103(a)(1) and (2) of the Clean Air Act (CAA), notice is hereby given that the EPA's Office of Air and Radiation (OAR) announces the opening of competition for the 2015 Clean Air Excellence Awards Program (CAEAP). The intent of the program is to recognize and honor outstanding, innovative efforts that help to make progress in achieving cleaner air. The CAEAP is open to both public and private entities. Entries are limited to efforts related to air quality in the United States. There are five general award categories: (1) Clean Air Technology; (2) Community Action; (3) Education/Outreach; (4) Regulatory/Policy Innovations; and (5) Transportation Efficiency Innovations. There are also two special awards categories: (1) Thomas W. Zosel Outstanding Individual Achievement Award; and (2) Gregg Cooke Visionary Program Award. Awards are given periodically and are for recognition only.

Entry Requirements: All applicants are asked to submit their entry on a CAEAP entry form, contained in the CAEAP Entry Package, which may be obtained from the CAAAC Web site at *http://www.epa.gov/air/cleanairawards/entry.html*. Applicants can also contact Ms. Jeneva Craig, Office of Air and Radiation, U.S. EPA by telephone at (202) 564–1674 or by email at *craig.jeneva@epa.gov*. The entry form is a simple, three-part form asking for general information on the applicant; a narrative description of the project; and three (3) independent references for the proposed entry. Applicants should also submit additional supporting documentation as necessary. Specific directions and information on filing an entry form are included in the Entry Package.

Judging and Award Criteria: EPA staff will use a screening process, with input from outside subject experts, as needed. Members of the CAAAC will provide advice to EPA on the entries. The EPA Assistant Administrator for Air and Radiation will make the final award decisions. Entries will be judged using both general criteria and criteria specific to each individual category. These criteria are listed in the 2015 Entry Package.

Dated: June 12, 2014.

Jeneva Craig,

Designated Federal Officer, Clean Air Act Advisory Committee, Office of Air and Radiation.

[FR Doc. 2014–14240 Filed 6–17–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2013–0049; FRL–9912–14]

Notice of Receipt of a Request To Voluntarily Cancel Certain Pesticide Registrations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In accordance with the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), EPA is issuing a notice of receipt of a request by a registrant to voluntarily cancel certain pesticide registrations. EPA intends to issue a cancellation order granting this request at the close of the comment period for this announcement. If this request is granted, any sale, distribution, or use of products listed in this notice will be permitted after the registrations have been cancelled only if such sale, distribution, or use is consistent with the terms as described in the cancellation order.

DATES: Comments must be received on or before July 18, 2014.

ADDRESSES: Submit your comments, identified by docket identification (ID) number EPA–HQ–OPP–2013–0049, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute.
- *Mail:* OPP Docket, Environmental Protection Agency Docket Center (EPA/DC), (28221T), 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001.

Submit written withdrawal request by mail to: Pesticide Re-Evaluation Division (7508P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001. ATTN: Rusty Wasem.

- *Hand Delivery:* To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at *http://www.epa.gov/dockets/contacts.html*. Additional instructions on commenting or visiting the docket, along with more information about dockets generally, is available at *http://www.epa.gov/dockets*.

FOR FURTHER INFORMATION CONTACT: Rusty Wasem, Pesticide Re-Evaluation Division (7508P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001; telephone number: (703) 305–6979; email address: *wasem.russell@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

This action is directed to the public in general, and may be of interest to a wide range of stakeholders including environmental, human health, and agricultural advocates; the chemical industry; pesticide users; and members of the public interested in the sale, distribution, or use of pesticides.

B. What should I consider as I prepare my comments for EPA?

1. *Submitting CBI.* Do not submit this information to EPA through regulations.gov or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that

is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for preparing your comments.* When submitting comments, remember to:

i. Identify the document by docket ID number and other identifying information (subject heading, **Federal Register** date and page number).

ii. Follow directions. The Agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

iii. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

iv. Describe any assumptions and provide any technical information and/or data that you used.

v. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

vi. Provide specific examples to illustrate your concerns and suggest alternatives.

vii. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

viii. Make sure to submit your comments by the comment period deadline identified.

II. What action is the Agency taking?

This notice announces receipt by the Agency of a request from Reckitt Benckiser LLC (Reckitt) to cancel 12 pesticide products registered under FIFRA section 3. These registrations are listed in sequence by registration number in Table 1 of this unit. The request for voluntary cancellation was conditioned on January 1, 2015 being the earliest effective date of cancellation, the Agency allowing certain sale and distribution of existing stocks of canceled product, and the Agency approving an alternative inert ingredient in the products prior to cancellation. EPA agreed to these conditions contingent upon:

1. Reckitt limiting further production of the 12 pesticide products, in the period prior to the effective date of cancellation, to filling orders from existing customers in accordance with shelf-set agreements and other contracts already in effect as of May 29, 2014;

2. Quantity limits on Reckitt's production of the 12 pesticide products; and

3. Reckitt submitting periodic reports on its production, sales and inventory of the 12 pesticide products.

At the end of the 30-day comment period, EPA intends to issue an order in the **Federal Register** canceling all of the affected registrations in a manner consistent with the conditional nature of the request for cancellation. Reckitt will be permitted to sell and distribute existing stocks to its existing customers until March 31, 2015. During this time period, Reckitt will also be permitted to ship product for the purpose of returning material back to Reckitt or for the purpose of disposal. Reckitt will be permitted to sell and distribute existing stocks after March 31, 2015 only for the limited purposes of returning material back to Reckitt or for disposal. The sale and distribution of existing stocks by persons other than Reckitt (e.g., distributors, retailers) will be permitted until such stocks are exhausted. Users will be allowed to use existing stocks until such stocks are exhausted, provided that such use is consistent with the terms of the previously approved labeling on, or that accompanied, the canceled product.

TABLE 1—REGISTRATIONS WITH PENDING REQUESTS FOR CANCELLATION

Registration No.	Product name	Chemical name
3282–3	D-Con Concentrate Kills Rats & Mice	Warfarin.
3282–4	D-Con Ready Mixed Kills Rats & Mice	Warfarin.
3282–9	D-Con Mouse Prufe Kills Mice	Warfarin.
3282–15	D-Con Pellets Kills Rats & Mice	Warfarin.
3282–65	D-Con Mouse Prufe II	Brodifacoum.
3282–66	D-Con Pellets Generation II	Brodifacoum.
3282–74	D-Con Bait Pellets II	Brodifacoum.
3282–81	D-Con Ready Mixed Generation II	Brodifacoum.
3282–85	D-Con Mouse-Prufe III	Difethialone.
3282–86	D-Con Bait Pellets III	Difethialone.
3282–87	D-Con II Ready Mix Baitbits III	Difethialone.
3282–88	D-Con Bait Packs III	Difethialone.

Table 2 of this unit includes the address of Reckitt.

TABLE 2—REGISTRANT REQUESTING VOLUNTARY CANCELLATION

EPA company No.	Company name and address
3282	Reckitt Benckiser LLC, 399 Interpace Parkway, Parsippany, NJ 07054.

III. What is the Agency's authority for taking this action?

Section 6(f)(1) of FIFRA provides that a registrant of a pesticide product may at any time request that any of its pesticide registrations be canceled. FIFRA further provides that, before acting on the request, EPA must publish a notice of receipt of any such request in the **Federal Register**.

Section 6(f)(1)(B) of FIFRA requires that before acting on a request for voluntary cancellation, EPA must provide a 30-day public comment period on the request for voluntary cancellation or use termination. In addition, FIFRA section 6(f)(1)(C) requires that EPA provide a 180-day comment period on a request for voluntary cancellation or termination of any minor agricultural use before granting the request, unless:

1. The registrants request a waiver of the comment period, or

2. The EPA Administrator determines that continued use of the pesticide would pose an unreasonable adverse effect on the environment.

The products listed in Table 1 of Unit II. do not represent minor agricultural uses. Therefore, the requests are not eligible for a 180-day comment period.

Accordingly, EPA will provide a 30-day comment period on the requests.

IV. Provisions for Disposition of Existing Stocks

Existing stocks are those stocks of canceled pesticide products that are in the United States and that were appropriately packaged, labeled, and released for shipment prior to the effective date of cancellation of the underlying registration. It is EPA's intention to issue a cancellation order treating existing stocks after cancellation of the registrations identified in Table 1 of Unit II. as follows:

1. Cancellation of the registrations will not become effective before January 1, 2015.

2. Reckitt will be permitted to sell and distribute existing stocks to its existing customers until March 31, 2015. During this time period, Reckitt will also be permitted to ship product for the purpose of returning material back to Reckitt or for the purpose of disposal.

3. Reckitt will be permitted to sell and distribute existing stocks after March 31, 2015 only for the limited purposes of returning material back to Reckitt or for disposal.

4. The sale and distribution of existing stocks by persons other than Reckitt (e.g., distributors, retailers) will be permitted until such stocks are exhausted. Users will be allowed to use existing stocks until such stocks are exhausted, provided that such use is consistent with the terms of the previously approved labeling on, or that accompanied, the canceled product.

List of Subjects

Environmental protection, Pesticides and pests.

Dated: June 11, 2014.

Richard P. Keigwin, Jr.,

Director, Pesticide Re-Evaluation Division, Office of Pesticide Programs.

[FR Doc. 2014–14250 Filed 6–17–14; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

Deletion of Consent Agenda Items From June 13, 2014 Sunshine Act Meeting

Date: June 13, 2014.

The following items have been adopted by the Commission and deleted from the list of consent agenda items scheduled for consideration at the Friday, June 13, 2014, Open Meeting and previously listed in the Commission's Notice of June 6, 2014.

Item No.	Bureau	Subject
1	MEDIA	TITLE: 6 Johnson Road Licenses, Inc., and Educational Media Foundation, Assignors, and Cumulus Licensing LLC, Assignee, Applications for Assignment of Stations WMEZ(FM), Pensacola, Florida, WXBM–FM, Milton, Florida, and WABD(FM), Mobile, Alabama. SUMMARY: The Commission will consider a Memorandum Opinion and Order concerning an Application for Review filed by ADX Communications of Escambia and Pensacola seeking review of Media Bureau decisions granting assignment applications.
2	MEDIA	TITLE: Amendment of Section 73.202(b), Table of Allotments, FM Broadcast Stations (Columbia, Missouri). SUMMARY: The Commission will consider a Memorandum Opinion and Order concerning an Application for Review filed by The Curators of the University of Missouri seeking review of the Media Bureau's dismissal of its rulemaking petition to reserve Channel 252C2 in Columbia, Missouri, for noncommercial educational use.
3	MEDIA	TITLE: Smile FM, Application for a Construction Permit For a New Noncommercial Educational FM Station at Yates, Michigan. SUMMARY: The Commission will consider a Memorandum Opinion and Order concerning an Application for Review filed by Smile FM seeking review of the Media Bureau's dismissal of its application for a new noncommercial educational FM station at Yates, Michigan.
4	MEDIA	TITLE: TJN, Inc., Application for a New NCE FM Station at Gold Beach, Oregon and UCB USA, Inc. Application for a New NCE FM Station at Brookings, Oregon. SUMMARY: The Commission will consider a Memorandum Opinion and Order concerning an Application for Review filed by TJN seeking review of a decision by the Media Bureau dismissing its application for a new noncommercial FM station at Gold Beach, Oregon.
5	MEDIA	TITLE: Scott Savage, Receiver, Assignor, Applications for Assignment of Licenses For Stations WFJO(FM), Folkston, Georgia, WHJX(FM), Baldwin, Florida, WSJF(FM), St. Augustine Beach, Florida, and WTHG(FM), Hinesville, Georgia. SUMMARY: The Commission will consider a Memorandum Opinion and Order concerning an Application for Review filed by Dr. Glenn W. Cherry and Charles W. Cherry, II, seeking review of several decisions by the Media Bureau.
6	MEDIA	TITLE: BVM Helping Hands, Application for Construction Permit for New Noncommercial Educational FM Station, Antioch, Illinois SUMMARY: The Commission will consider a Memorandum Opinion and Order concerning an Application for Review filed by Chicago Public Media seeking review of a decision by the Media Bureau granting a new noncommercial educational FM station in Antioch, Illinois to BVM Helping Hands.
7	MEDIA	TITLE: New Jersey Public Broadcasting Authority, Application for a New NCE FM Station at Bernardsville, New Jersey and World Revivals, Inc., Application for a New NCE FM Station at Chatham, New Jersey. SUMMARY: The Commission will consider a Memorandum Opinion and Order concerning an Application for Review filed by World Revivals, Inc., seeking review of several decisions by the Media Bureau.

Federal Communications Commission.

Marlene H. Dortch,

Secretary, Office of the Secretary, Office of Managing Director.

[FR Doc. 2014–14396 Filed 6–16–14; 4:15 pm]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

Sunshine Act Meeting; Open Commission Meeting; Friday, June 13, 2014

Date: June 6, 2014.

The Federal Communications Commission will hold an Open Meeting on the subjects listed below on Friday, June 13, 2014 which is scheduled to commence at 10:30 a.m. in Room TW–C305, at 445 12th Street SW., Washington, DC.

Item No.	Bureau	Subject
1	Wireline Competition	PRESENTATION: The Commission will hear a presentation with an update on the efforts to transition circuit-switched networks to Internet Protocol (IP) networks. The presentation will include a status report on the voluntary experiments proposed by AT&T designed to assess how the transition to IP networks affects users.
2	MEDIA	PRESENTATION: The Commission will hear a presentation with an update on the continuing efforts to launch new and diverse voices to the American public via increased access to Low Power FM radio stations.

* * * * *

Consent Agenda

The Commission will consider the following subjects listed below as a consent agenda and these items will not be presented individually:

1	MEDIA	TITLE: 6 Johnson Road Licenses, Inc., and Educational Media Foundation, Assignors, and Cumulus Licensing LLC, Assignee, Applications for Assignment of Stations WMEZ(FM), Pensacola, Florida, WXBM–FM, Milton, Florida, and WABD(FM), Mobile, Alabama. SUMMARY: The Commission will consider a Memorandum Opinion and Order concerning an Application for Review filed by ADX Communications of Escambia and Pensacola seeking review of Media Bureau decisions granting assignment applications.
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The meeting site is fully accessible to people using wheelchairs or other mobility aids. Sign language interpreters, open captioning, and assistive listening devices will be provided on site. Other reasonable accommodations for people with disabilities are available upon request. In your request, include a description of the accommodation you will need and a way we can contact you if we need more information. Last minute requests will be accepted, but may be impossible to fill. Send an email to: *fcc504@fcc.gov* or call the Consumer & Governmental Affairs Bureau at 202–418–0530 (voice), 202–418–0432 (tty).

Additional information concerning this meeting may be obtained from Meribeth McCarrick, Office of Media Relations, (202) 418–0500; TTY 1–888–

835–5322. Audio/Video coverage of the meeting will be broadcast live with open captioning over the Internet from the FCC Live Web page at *www.fcc.gov/live*.

For a fee this meeting can be viewed live over George Mason University's Capitol Connection. The Capitol Connection also will carry the meeting live via the Internet. To purchase these services, call (703) 993–3100 or go to *www.capitolconnection.gmu.edu* <*http://www.capitolconnection.gmu.edu*>.

Copies of materials adopted at this meeting can be purchased from the FCC's duplicating contractor, Best Copy and Printing, Inc. (202) 488–5300; Fax (202) 488–5563; TTY (202) 488–5562. These copies are available in paper format and alternative media, including large print/type; digital disk; and audio and video tape. Best Copy and Printing, Inc. may be reached by email at *FCC@BCPIWEB.com*.

Federal Communications Commission.

Marlene H. Dortch,

Secretary, Office of the Secretary, Office of Managing Director.

[FR Doc. 2014–14394 Filed 6–16–14; 4:15 pm]

BILLING CODE 6712–01–P

FEDERAL MARITIME COMMISSION

Agency Information Collection Activities: 60-Day Public Comment Request

AGENCY: Federal Maritime Commission.

ACTION: Notice and request for comments.

SUMMARY: As part of our continuing effort to reduce paperwork and respondent burden, and as required by the Paperwork Reduction Act of 1995, the Federal Maritime Commission (Commission) invites comments on the continuing information collections (extensions with no changes) listed below in this notice.

DATES: Written comments must be submitted on or before August 20, 2014.

ADDRESSES: Address all comments to: Vern W. Hill, Managing Director, Office of the Managing Director, Federal Maritime Commission, 800 North Capitol Street NW., Washington, DC 20573, Phone: (202) 523–5800, Email: *omd@fmc.gov.*

Please send separate comments for each specific information collection listed below. You must reference the information collection's title and OMB number in your comments.

FOR FURTHER INFORMATION CONTACT: Copies of the information collections and instructions, or copies of any comments received, may be obtained by contacting Donna Lee on (202) 523–5800 or email at *dlee@fmc.gov.*

SUPPLEMENTARY INFORMATION:

Request for Comments

The Commission, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to comment on the continuing information collections listed in this notice, as required by the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

Comments submitted in response to this notice will be included or summarized in our request for Office of Management and Budget (OMB) approval of the relevant information collection. All comments are part of the public record and subject to disclosure. Please do not include any confidential or inappropriate material in your comments. We invite comments on: (1) The necessity and utility of the proposed information collection for the proper performance of the agency's functions; (2) the accuracy of the estimated burden; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

Information Collections Open for Comment

Title: 46 CFR Part 565—Controlled Carriers.

OMB Approval Number: 3072–0060 (Expires September 30, 2014).

Abstract: Section 9 of the Shipping Act of 1984, 46 U.S.C. 40701–40706, requires that the Commission monitor the practices of controlled carriers to ensure that they do not maintain rates or charges in their tariffs and service contracts that are below a level that is just and reasonable; nor establish, maintain or enforce unjust or unreasonable classifications, rules or regulations in those tariffs or service contracts which result or are likely to result in the carriage or handling of cargo at rates or charges that are below a just and reasonable level. 46 CFR Part 565 establishes the method by which the Commission determines whether a particular ocean common carrier is a controlled carrier subject to section 9 of the Shipping Act of 1984. When a government acquires a controlling interest in an ocean common carrier, or when a controlled carrier newly enters a United States trade, the Commission's rules require that such a carrier notify the Commission of these events.

Current Actions: There are no changes to this information collection, and it is being submitted for extension purposes only.

Type of Review: Extension.

Needs and Uses: The Commission uses these notifications in order to effectively discharge its statutory duty to determine whether a particular ocean common carrier is a controlled carrier and therefore subject to the requirements of section 9 of the Shipping Act of 1984.

Frequency: The submission of notifications from controlled carriers is not assigned to a specific time frame by the Commission; they are submitted as circumstances warrant. The Commission only requires notification when a majority portion of an ocean common carrier becomes owned or controlled by a government, or when a controlled carrier newly begins operation in any United States trade.

Type of Respondents: Controlled carriers are ocean common carriers which are owned or controlled by a government.

Number of Annual Respondents: It is estimated that 4 of the currently classified controlled carriers may respond in any given year. Classifications are reviewed periodically to determine current status of respondents and to increase or decrease the number of controlled carriers based on new circumstances. The Commission cannot anticipate when a new carrier may enter the United States trade; therefore, the number of annual respondents may fluctuate from year to year and could increase to 10 or more at any time.

Estimated Time per Response: The estimated time for compliance is 7 person-hours per year.

Total Annual Burden: The Commission estimates the person-hour burden required to make such notifications at 28 person-hours per year.

Title: 46 CFR Part 525—Marine Terminal Operator Schedules and Related Form FMC–1.

OMB Approval Number: 3072–0061 (Expires September 30, 2014).

Abstract: Section 8(f) of the Shipping Act of 1984, 46 U.S.C. 40501(f), provides that a marine terminal operator (MTO) may make available to the public a schedule of its rates, regulations, and practices, including limitations of liability for cargo loss or damage, pertaining to receiving, delivering, handling, or storing property at its marine terminal. The Commission's

rules governing MTO schedules are set forth at 46 CFR Part 525.

Current Actions: There are no changes to this information collection, and it is being submitted for extension purposes only.

Type of Review: Extension.

Needs and Uses: The Commission uses information obtained from Form FMC–1 to determine the organization name, organization number, home office address, name and telephone number of the firm's representatives and the location of MTO schedules of rates, regulations and practices, and publisher, should the MTOs determine to make their schedules available to the public, as set forth in section 8(f) of the Shipping Act.

Frequency: This information is collected prior to an MTO's commencement of its marine terminal operations.

Type of Respondents: Persons operating as MTOs.

Number of Annual Respondents: The Commission estimates the respondent universe at 29, of which 15 opt to make their schedules available to the public.

Estimated Time per Response: The time per response for completing Form FMC–1 averages 0.5 person hours, and approximately 5 person-hours for related MTO schedules.

Total Annual Burden: The Commission estimates the total person-hour burden at 90 person-hours.

Title: 46 CFR Part 520—Carrier Automated Tariffs and Related Form FMC–1.

OMB Approval Number: 3072–0064 (Expires September 30, 2014).

Abstract: Except with respect to certain specified commodities, section 8(a) of the Shipping Act of 1984, 46 U.S.C. 40501(a)–(c), requires that each common carrier and conference shall keep open to public inspection, in an automated tariff system, tariffs showing its rates, charges, classifications, rules, and practices between all ports and points on its own route and on any through transportation route that has been established. In addition, individual carriers or agreements among carriers are required to make available in tariff format certain enumerated essential terms of their service contracts. 46 U.S.C. 40502. The Commission is responsible for reviewing the accessibility and accuracy of automated tariff systems, in accordance with its regulations set forth at 46 CFR Part 520.

Current Actions: There are no changes to this information collection, and it is being submitted for extension purposes only.

Type of Review: Extension.

Needs and Uses: The Commission uses information obtained from Form FMC–1 to ascertain the location of common carrier and conference tariff publications, and to access their provisions regarding rules, rates, charges and practices.

Frequency: This information is collected when common carriers or conferences publish tariffs.

Type of Respondents: Persons desiring to operate as common carriers or conferences.

Number of Annual Respondents: The Commission estimates there are 4,900 Carrier Automated Tariffs. It is estimated that the number of annual respondents will be 1,882.

Estimated Time per Response: The time per response ranges from 0.1 to 2 person-hours for reporting and recordkeeping requirements contained in the rules, and 0.5 person-hours for completing Form FMC–1.

Total Annual Burden: The Commission estimates the total person-hour burden at 2,735 person-hours.

Title: 46 CFR Part 530—Service Contracts and Related Form FMC–83.

OMB Approval Number: 3072–0065 (Expires September 30, 2014).

Abstract: Section 8(c) of the Shipping Act of 1984, 46 U.S.C. 40502, requires service contracts, except those dealing with bulk cargo, forest products, recycled metal scrap, new assembled motor vehicles, waste paper or paper waste, and their related amendments and notices to be filed confidentially with the Commission.

Current Actions: There are no changes to this information collection, and it is being submitted for extension purposes only.

Type of Review: Extension.

Needs and Uses: The Commission monitors service contract filings for acts prohibited by the Shipping Act of 1984.

Frequency: The Commission has no control over how frequently service contracts are entered into; this is solely a matter between the negotiating parties. When parties enter into a service contract, it must be filed with the Commission.

Type of Respondents: Parties that enter into service contracts are ocean common carriers and agreements among ocean common carriers on the one hand, and shippers or shipper's associations on the other.

Number of Annual Respondents: The Commission estimates an annual respondent universe of 103.

Estimated Time per Response: The time per response ranges from 0.1 to 1 person-hours for reporting and recordkeeping requirements contained in the rules, and 0.1 person-hours for completing Form FMC–83.

Total Annual Burden: The Commission estimates the total person-hour burden at 74,721 person-hours.

Title: 46 CFR Part 531—NVOCC Service Arrangements and Related Form FMC–78.

OMB Approval Number: 3072–0070 (Expires September 30, 2014).

Abstract: Section 16 of the Shipping Act of 1984, 46 U.S.C. 40103, authorizes the Commission to exempt by rule ''any class of agreements between persons subject to this part or any specified activity of those persons from any requirement of this part if the Commission finds that the exemption will not result in substantial reduction in competition or be detrimental to commerce. The Commission may attach conditions to an exemption and may, by order, revoke an exemption.'' 46 CFR Part 531 allows non-vessel-operating common carriers (NVOCCs) and shippers' associations with NVOCC members to act as shipper parties in NVOCC Service Arrangements (NSAs), and to be exempt from certain tariff publication requirements of the Shipping Act provided the carriage in question is done pursuant to an NSA filed with the Commission and the essential terms are published in the NVOCC's tariff.

Current Actions: There are no changes to this information collection, and it is being submitted for extension purposes only.

Type of Review: Extension.

Needs and Uses: The Commission uses filed NSAs and associated data for monitoring and investigatory purposes and, in its proceedings, to adjudicate related issues raised by private parties.

Frequency: The filing of NSAs is not assigned a specific time by the Commission; NSAs are filed as they may be entered into by private parties. When parties enter into an NSA, it must be filed with the Commission.

Type of Respondents: Parties that enter into NSAs are NVOCCs and shippers' associations with NVOCC members.

Number of Annual Respondents: The Commission estimates an annual respondent universe of 79.

Estimated Time per Response: The time per response ranges from 0.1 to 1 person-hours for reporting and recordkeeping requirements contained in the rules, and 1 person-hour for completing Form FMC–78.

Total Annual Burden: The Commission estimates the total person-hour burden at 895 person-hours.

Karen V. Gregory,

Secretary.

[FR Doc. 2014–14256 Filed 6–17–14; 8:45 am]

BILLING CODE 6730–01–P

FEDERAL MARITIME COMMISSION

Notice of Agreements Filed

The Commission hereby gives notice of the filing of the following agreements under the Shipping Act of 1984. Interested parties may submit comments on the agreements to the Secretary, Federal Maritime Commission, Washington, DC 20573, within twelve days of the date this notice appears in the **Federal Register**. Copies of the agreements are available through the Commission's Web site (*www.fmc.gov*) or by contacting the Office of Agreements at (202)–523–5793 or *tradeanalysis@fmc.gov*.

Agreement No.: 012157–002.

Title: CSCL/CMA CGM Slot Exchange Agreement Asia—U.S. East Coast.

Parties: China Shipping Container Lines Co., Ltd., China Shipping Container Lines (Hong Kong) Co., Ltd., and CMA CGM S.A.

Filing Party: Draughn B. Arbona, Esq., Senior Counsel, CMA CGM (America), Inc. 5701 Lake Wright Drive, Norfolk, VA 23502–1868.

Synopsis: The amendment reduces the slot allocation of each party on their respective services.

Agreement No.: 012284.

Title: CSAV/Norasia/HLAG Jamaica Space Charter Agreement.

Parties: Compania Sud America de Vapores S.A.; Norasia Container Lines Limited; and Hapag-Lloyd AG.

Filing Party: Wayne Rohde, Esq.; Cozen O'Connor; 1627 I Street NW., Suite 1100; Washington, DC 20006.

Synopsis: The agreement authorizes Hapag-Lloyd to charter space to CSAV and Norasia in the trade between the U.S. East Coast and Jamaica.

By Order of the Federal Maritime Commission.

Dated: June 13, 2014.

Karen V. Gregory,

Secretary.

[FR Doc. 2014–14254 Filed 6–17–14; 8:45 am]

BILLING CODE P

FEDERAL MARITIME COMMISSION

Ocean Transportation Intermediary License Applicants

The Commission gives notice that the following applicants have filed an application for an Ocean Transportation Intermediary (OTI) license as a Non-Vessel-Operating Common Carrier (NVO) and/or Ocean Freight Forwarder (OFF) pursuant to section 19 of the Shipping Act of 1984 (46 U.S.C. 40101). Notice is also given of the filing of applications to amend an existing OTI license or the Qualifying Individual (QI) for a licensee.

Interested persons may contact the Office of Ocean Transportation Intermediaries, Federal Maritime Commission, Washington, DC 20573, by telephone at (202) 523–5843 or by email at *OTI@fmc.gov*.

Argyle Customs and Forwarding, LLC (NVO & OFF), 1410 West Ganson Street, Jackson, MI 49201, Officer: Gregory D. Chevalier, Member/Member (QI), Application Type: New NVO & OFF License.

Arrow Logistics Services, Inc. (NVO), 7900 NW. 68th Street, Miami, FL 33166, Officers: Ernesto O. Del Riego, Vice President (QI), Erich M. Bendixen, President, Application Type: New NVO License.

Braid Logistics (North America), LLC (NVO & OFF), 365 Canal Street, Suite 1100, New Orleans, LA 70130, Officers: John J. Lyons, Vice President (QI), Christopher White, Member, Application Type: New NVO & OFF License.

Clare Freight Int'l (U.S.A.), Inc. (NVO), 177–14 149th Road, 2nd Floor, Jamaica, NY 11434, Officers: Claire Moachi Lee, President (QI), John Lee, Application Type: QI Change.

Confianca Logistics LLC (NVO), 11700 NW. 102nd Road, Suite 16, Medley, FL 33178, Officers: Rodrigo Stegani, Manager (QI), Mauro Do Nascimento Do Almeida, Manager, Application Type: New NVO License.

Damco International B.V. dba Damco dba Damco Maritime dba Damco Sea and Air (NVO), Turfmarkt 107, 2511 DP Den Haag, Netherlands, Officers: James Percival, Compliance Officer (QI), Morten Englestoft, Director, Application Type: New NVO License.

DJS International Services, Inc. (NVO & OFF), 4215 Gateway Drive, Suite 100, Colleyville, TX 76034, Officers: David M. Meyer, Vice President (QI), Melissa S. Meyer, Treasurer, Application Type: Additional QI.

Global Logistics Services, Inc. (NVO & OFF), 9667 NW. 33rd Street, Miami, FL 33172, Officers: Ana Conlan, Vice President (QI), Edward Boroski, CEO, Application Type: Name Change to EWC Ocean Services, Inc.

Global Vision Group, Inc. (NVO & OFF), 2227 Salisbury Highway, Statesville, NC 28677, Officers: Steven P. Murphy, Assistant Vice President (QI), Jeff B. Harvey, President, Application Type: QI Change.

Latin Link Logistics, LLC (NVO & OFF), 10405 NW. 37th Terrace, Miami, FL 33178, Officer: Shariff Gonnella, President (QI), Application Type: QI Change.

Marinex Logistics LLC (NVO & OFF), 11 Chimney Ridge Court, Washington TWP, NJ 07676, Officer: Alp Kosi, President (QI), Application Type: New NVO & OFF License.

Rand Whitney Packaging Corp dba Horn International Forwarding (NVO), 580 Fort Pond Road, Lancaster, MA 01523, Officers: Michael V. Yost, Vice President (QI), Nicholas Smith, President, Application Type: New NVO License.

Rodawi International Corp. (NVO & OFF), 6384 NW. 99th Avenue, Miami, FL 33178, Officer: Rosa Rodriguez, President (QI), Application Type: New NVO & OFF License.

SCT Worldwide Logistics LLC (NVO & OFF), 1300 Andrea Drive, Waycross, GA 31501, Officer: Steven C. Thornton, Managing Member (QI), Application Type: New NVO & OFF License.

Siati Express Inc. (NVO & OFF), 6117 NW. 72nd Avenue, Miami, FL 33166, Officers: Jose F. Banderas, Vice President (QI), Byron F. Mora, President, Application Type: New NVO & OFF License.

St. Blue & Co., Inc. (NVO), 21023 Main Street, Unit A, Carson, CA 90745, Officer: Sammy Son, President (QI), Application Type: Add Trade Name AP Logistics.

Transcarveca, U.S.A. Corp. (OFF), 2510 NW. 97th Avenue, Suite 120, Miami, FL 33172, Officer: Luis A. Fuenmayor, President (QI), Application Type: Add Trade Name Teamfreight Forwarding Company.

Transitnow LLC (NVO), 26 W. Linden Ave., Suite #3, Linden, NJ 07036, Officers: David Menteshashvili, Member (QI), Avtandil Mikeladze, General Manager, Application Type: New NVO License.

United Liberty Express Co. Inc. dba United Liberty Express (NVO), 201–3701 East Hastings Street, Burnaby, V5C 2H6, Canada, Officers: Dmitry Zhdanov, Director (QI), Anastasia Zhdanova, Director, Application Type: New NVO License.

World Cargo Solutions LLC dba World Cargo Lines (NVO & OFF), 1926

Rankin Road, Suite 100, Houston, TX 77073, Officers: Jacob Mathew, Managing Member (QI), Jitendra Prasad, Managing Member, Application Type: New NVO & OFF License.

By the Commission.

Dated: June 13, 2014.

Karen V. Gregory,

Secretary.

[FR Doc. 2014–14257 Filed 6–17–14; 8:45 am]

BILLING CODE 6730–01–P

FEDERAL MARITIME COMMISSION

Notice of Request for Additional Information

The Commission gives notice that it has formally requested that the parties to the below listed agreement provide additional information pursuant to 46 U.S.C. 40304(d). This action prevents the agreement from becoming effective as originally scheduled. Interested parties may file comments within fifteen (15) days after publication of this notice in the **Federal Register**.

Agreement No.: 012274.

Title: OVSA/PIL Space Charter Agreement.

Parties: Hamburg Sud; Hapag-Lloyd AG; CMA CGM S.A./ANL Singapore Pte Ltd. (acting as a single party); and Pacific International Lines (Pte) Ltd.

Dated: June 13, 2014.

By Order of the Federal Maritime Commission.

Karen V. Gregory,

Secretary.

[FR Doc. 2014–14255 Filed 6–17–14; 8:45 am]

BILLING CODE P

FEDERAL MINE SAFETY AND HEALTH REVIEW COMMISSION

Sunshine Act Meeting Notice

June 13, 2014.

TIME AND DATE: 1:00 p.m., Thursday, June 26, 2014.

PLACE: The Richard V. Backley Hearing Room, Room 511N, 1331 Pennsylvania Avenue NW., Washington, DC 20004 (entry from F Street entrance).

STATUS: Open.

MATTERS TO BE CONSIDERED: The Commission will consider and act upon the following in open session: *Secretary of Labor* v. *Tilden Mining Co., LC,* Docket No. LAKE 2008–503–M. (Issues include whether a standard requiring periodic continuity and resistance testing of grounding systems applies to extension cords and power cords.)

Any person attending this meeting who requires special accessibility features and/or auxiliary aids, such as sign language interpreters, must inform the Commission in advance of those needs. Subject to 29 CFR 2706.150(a)(3) and 2706.160(d).

CONTACT PERSON FOR MORE INFO: Jean Ellen (202) 434–9950/(202) 708–9300 for TDD Relay/1–800–877–8339 for toll free.

Emogene Johnson,

Administrative Assistant.

[FR Doc. 2014–14322 Filed 6–16–14; 11:15 am]

BILLING CODE 6735–01–P

FEDERAL MINE SAFETY AND HEALTH REVIEW COMMISSION

Sunshine Act Meeting Notice

June 13, 2014.

TIME AND DATE: 10:00 a.m., Thursday, June 26, 2014.

PLACE: The Richard V. Backley Hearing Room, Room 511N, 1331 Pennsylvania Avenue NW., Washington, DC 20004 (entry from F Street entrance).

STATUS: Open.

MATTERS TO BE CONSIDERED: The Commission will hear oral argument in the matter *Secretary of Labor* v. *Tilden Mining Co., LC,* Docket No. LAKE 2008–503–M. (Issues include whether a standard requiring periodic continuity and resistance testing of grounding systems applies to extension cords and power cords.)

Any person attending this oral argument who requires special accessibility features and/or auxiliary aids, such as sign language interpreters, must inform the Commission in advance of those needs. Subject to 29 CFR 2706.150(a)(3) and 2706.160(d).

CONTACT PERSON FOR MORE INFO: Jean Ellen (202) 434–9950/(202) 708–9300 for TDD Relay/1–800–877–8339 for toll free.

Emogene Johnson,

Administrative Assistant.

[FR Doc. 2014–14321 Filed 6–16–14; 11:15 am]

BILLING CODE 6735–01–P

FEDERAL RESERVE SYSTEM

Proposed Agency Information Collection Activities; Comment Request

AGENCY: Board of Governors of the Federal Reserve System.

SUMMARY: On June 15, 1984, the Office of Management and Budget (OMB) delegated to the Board of Governors of the Federal Reserve System (Board) its approval authority under the Paperwork Reduction Act (PRA), pursuant to 5 CFR 1320.16, to approve of and assign OMB control numbers to collection of information requests and requirements conducted or sponsored by the Board under conditions set forth in 5 CFR part 1320 Appendix A.1. Board-approved collections of information are incorporated into the official OMB inventory of currently approved collections of information. Copies of the Paperwork Reduction Act Submission, supporting statements and approved collection of information instruments are placed into OMB's public docket files. The Federal Reserve may not conduct or sponsor, and the respondent is not required to respond to, an information collection that has been extended, revised, or implemented on or after October 1, 1995, unless it displays a currently valid OMB control number.

DATES: Comments must be submitted on or before August 18, 2014.

ADDRESSES: You may submit comments, identified by *FR 3075,* by any of the following methods:

- *Agency Web site: http://www.federalreserve.gov.* Follow the instructions for submitting comments at *http://www.federalreserve.gov/apps/foia/proposedregs.aspx.*
- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Email: regs.comments@federalreserve.gov.* Include OMB number in the subject line of the message.
- *FAX:* (202) 452–3819 or (202) 452–3102.
- *Mail:* Robert deV. Frierson, Secretary, Board of Governors of the Federal Reserve System, 20th Street and Constitution Avenue NW., Washington, DC 20551.

All public comments are available from the Board's Web site at *http://www.federalreserve.gov/apps/foia/proposedregs.aspx* as submitted, unless modified for technical reasons. Accordingly, your comments will not be edited to remove any identifying or contact information. Public comments may also be viewed electronically or in paper form in Room MP–500 of the Board's Martin Building (20th and C Streets NW.) between 9:00 a.m. and 5:00 p.m. on weekdays.

Additionally, commenters may send a copy of their comments to the OMB Desk Officer—Shagufta Ahmed—Office of Information and Regulatory Affairs, Office of Management and Budget, New Executive Office Building, Room 10235

725 17th Street NW., Washington, DC 20503 or by fax to (202) 395–6974.

FOR FURTHER INFORMATION CONTACT: A copy of the PRA OMB submission, including the proposed reporting form and instructions, supporting statement, and other documentation will be placed into OMB's public docket files, once approved. These documents will also be made available on the Federal Reserve Board's public Web site at: *http://www.federalreserve.gov/apps/reportforms/review.aspx* or may be requested from the agency clearance officer, whose name appears below.

Federal Reserve Board Clearance Officer—Cynthia Ayouch—Office of the Chief Data Officer, Board of Governors of the Federal Reserve System, Washington, DC 20551 (202) 452–3829. Telecommunications Device for the Deaf (TDD) users may contact (202) 263–4869, Board of Governors of the Federal Reserve System, Washington, DC 20551.

SUPPLEMENTARY INFORMATION:

Request for Comment on Information Collection Proposal

The following information collection, which is being handled under this delegated authority, has received initial Board approval and is hereby published for comment. At the end of the comment period, the proposed information collection, along with an analysis of comments and recommendations received, will be submitted to the Board for final approval under OMB delegated authority. Comments are invited on the following:

a. Whether the proposed collection of information is necessary for the proper performance of the Federal Reserve's functions; including whether the information has practical utility;

b. The accuracy of the Federal Reserve's estimate of the burden of the proposed information collection, including the validity of the methodology and assumptions used;

c. Ways to enhance the quality, utility, and clarity of the information to be collected;

d. Ways to minimize the burden of information collection on respondents, including through the use of automated collection techniques or other forms of information technology; and

e. Estimates of capital or start up costs and costs of operation, maintenance, and purchase of services to provide information.

Proposal To Approve Under OMB Delegated Authority the Implementation of the Following Report

Report title: Policy Impact Survey.

Agency form number: FR 3075.

OMB control number: 7100-to be assigned.

Frequency: On occasion.

Reporters: Bank holding companies (BHCs) (and their subsidiaries), savings and loan holding companies (SLHCs), non-BHC/SLHC systemically important financial institutions (SIFIs), the combined domestic operations of certain foreign banking organizations (FBOs), state member banks (SMBs), Edge and agreement corporations, and U.S. branches and agencies for foreign banks authorized under specific statutes noted below.

Estimated annual reporting hours: 58,500 hours.

Estimated average hours per response: 60 hours.

Estimated number of respondents: 65.

General description of report: This information collection is generally authorized under sections 2A and 12A of the Federal Reserve Act. Section 2A requires that the Board of Governors of the Federal Reserve System and the Federal Open Market Committee (FOMC) maintain long run growth of the monetary and credit aggregates commensurate with the economy's long run potential to increase production, so as to promote effectively the goals of maximum employment, stable prices, and moderate long-term interest rates. 12 U.S.C. 225a. In addition, under section 12A of the Federal Reserve Act, the FOMC is required to implement regulations relating to the open market operations conducted by Federal Reserve Banks with a view to accommodating commerce and business and with regard to the regulations' bearing upon the general credit situation of the country. 12 U.S.C. 263. The authority of the Federal Reserve to collect economic data to carry out the requirements of these provisions is implicit. Accordingly, the Federal Reserve is authorized to use the FR 3075 by sections 2A and 12A of the Federal Reserve Act.

Additionally, depending upon the survey respondent, the information collection may be authorized under a more specific statute. Specifically, the Board is authorized to collect information from: BHCs (and their subsidiaries) under section 5(c) of the Bank Holding Company Act (12 U.S.C. 1844(c)); SLHCs under section 10(b)(2) of the Home Owners Loan Act (12 U.S.C. 1467a(b)(2)); non-BHC/SLHC SIFIs under section 161(a) of the Dodd-Frank Act (12 U.S.C. 5361(a)); the combined domestic operations of certain FBOs under section 8(a) of the International Banking Act of 1978 (12 U.S.C. 3106(a)) and section 5(c) of the Bank Holding Company Act (12 U.S.C. 1844(c)); SMBs under section 9 of the Federal Reserve Act (12 U.S.C. 324); Edge and agreement corporations under sections 25 and 25A of the Federal Reserve Act (12 U.S.C. 602 and 625) and U.S. branches and agencies of foreign banks under section 7(c)(2) of the International Banking Act of 1978 (12 U.S.C. 3105(c)(2) and under section 7(a) of the Federal Deposit Insurance Act (12 U.S.C. 1817(a)).

The Federal Reserve expects the majority of surveys to be conducted on a voluntary basis. However, with respect to collections of information from BHCs (and their subsidiaries), SLHCs, non-BHC/SLHC SIFIs, the combined domestic operations of certain foreign banking organizations, state member banks, Edge and agreement corporations, and U.S. branches and agencies for foreign banks authorized under the specific statutes noted above, the Federal Reserve could make the obligation to respond mandatory.

The ability of the Federal Reserve to maintain the confidentiality of information provided by respondents to the FR 3075 surveys will have to be determined on a case-by-case basis depending on the type of information provided for a particular survey. Depending upon the survey questions, confidential treatment may be warranted under exemptions 4, 6, and 8 of the Freedom of Information Act (FOIA). Exemption 4 protects from disclosure trade secrets and commercial or financial information, while exemption 6 protects information ''the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.'' See 5 U.S.C. 552(b)(4) and (b)(6). If the survey is mandatory and is undertaken as part of the supervisory process, information could be protected under FOIA exemption 8, which protects information relating to examination reports. 5 U.S.C. 552(b)(8).

Abstract: The Federal Reserve proposes to implement FR 3075, which would collect information from select institutions regulated by the Federal Reserve in order to assess the effects of proposed, pending, or recently-adopted policy changes at the domestic and international levels. For example, the survey would collect information used for certain qualitative impact studies (QISs) sponsored by bodies such as the Basel Committee on Banking Supervision and the Financial Stability Board. Recent QISs have included the Basel III monitoring exercise, which monitors the global impact of the Basel

III framework,[1] and the global systemically important bank exercise, which assesses a firm's systemic risk profile.[2] Since the collected data may change from survey to survey, there would be no fixed reporting form. The data submission timeline for each survey would be determined prior to the distribution of the survey materials. In soliciting participation, the Federal Reserve would explain to respondents the purpose of the survey and how the data would be used. While the number of respondents may fluctuate between surveys, the survey would be conducted up to 15 times per year.

Board of Governors of the Federal Reserve System, June 12, 2014.

Robert deV. Frierson,

Secretary of the Board.

[FR Doc. 2014–14208 Filed 6–17–14; 8:45 am]

BILLING CODE 6210–01–P

[1] For more information on the Basel III monitoring exercise, see *www.bis.org/bcbs/qis/*.

[2] For more information on the G–SIB exercise, see *www.bis.org/bcbs/gsib/*.

FEDERAL RESERVE SYSTEM

Proposed Agency Information Collection Activities; Comment Request

AGENCY: Board of Governors of the Federal Reserve System.

SUMMARY: On June 15, 1984, the Office of Management and Budget (OMB) delegated to the Board of Governors of the Federal Reserve System (Board) its approval authority under the Paperwork Reduction Act (PRA), pursuant to 5 CFR 1320.16, to approve of and assign OMB control numbers to collection of information requests and requirements conducted or sponsored by the Board under conditions set forth in 5 CFR part 1320 Appendix A.1. Board-approved collections of information are incorporated into the official OMB inventory of currently approved collections of information. Copies of the Paperwork Reduction Act Submission, supporting statements and approved collection of information instruments are placed into OMB's public docket files. The Federal Reserve may not conduct or sponsor, and the respondent is not required to respond to, an information collection that has been extended, revised, or implemented on or after October 1, 1995, unless it displays a currently valid OMB control number.

DATES: Comments must be submitted on or before August 18, 2014.

ADDRESSES: You may submit comments, identified by *FR Y–7Q,* by any of the following methods:

- *Agency Web site: http://www.federalreserve.gov*. Follow the instructions for submitting comments at *http://www.federalreserve.gov/apps/foia/proposedregs.aspx*.
- *Federal eRulemaking Portal: http://www.regulations.gov*. Follow the instructions for submitting comments.
- *Email: regs.comments@federalreserve.gov*. Include OMB number in the subject line of the message.
- *FAX:* (202) 452–3819 or (202) 452–3102.
- *Mail:* Robert deV. Frierson, Secretary, Board of Governors of the Federal Reserve System, 20th Street and Constitution Avenue NW., Washington, DC 20551.

All public comments are available from the Board's Web site at *http://www.federalreserve.gov/apps/foia/proposedregs.aspx* as submitted, unless modified for technical reasons. Accordingly, your comments will not be edited to remove any identifying or contact information. Public comments may also be viewed electronically or in paper form in Room MP–500 of the Board's Martin Building (20th and C Streets NW.) between 9:00 a.m. and 5:00 p.m. on weekdays.

Additionally, commenters may send a copy of their comments to the OMB Desk Officer—Shagufta Ahmed—Office of Information and Regulatory Affairs, Office of Management and Budget, New Executive Office Building, Room 10235 725 17th Street NW., Washington, DC 20503 or by fax to (202) 395–6974.

FOR FURTHER INFORMATION CONTACT: A copy of the PRA OMB submission, including the proposed reporting form and instructions, supporting statement, and other documentation will be placed into OMB's public docket files, once approved. These documents will also be made available on the Federal Reserve Board's public Web site at: *http://www.federalreserve.gov/apps/reportforms/review.aspx* or may be requested from the agency clearance officer, whose name appears below.

Federal Reserve Board Clearance Officer—Cynthia Ayouch—Office of the Chief Data Officer, Board of Governors of the Federal Reserve System, Washington, DC 20551 (202) 452–3829. Telecommunications Device for the Deaf (TDD) users may contact (202) 263–4869, Board of Governors of the Federal Reserve System, Washington, DC 20551.

SUPPLEMENTARY INFORMATION:

Request for Comment on Information Collection Proposal

The following information collection, which is being handled under this delegated authority, has received initial Board approval and is hereby published for comment. At the end of the comment period, the proposed information collection, along with an analysis of comments and recommendations received, will be submitted to the Board for final approval under OMB delegated authority. Comments are invited on the following:

a. Whether the proposed collection of information is necessary for the proper performance of the Federal Reserve's functions; including whether the information has practical utility;

b. The accuracy of the Federal Reserve's estimate of the burden of the proposed information collection, including the validity of the methodology and assumptions used;

c. Ways to enhance the quality, utility, and clarity of the information to be collected;

d. Ways to minimize the burden of information collection on respondents, including through the use of automated collection techniques or other forms of information technology; and

e. Estimates of capital or start up costs and costs of operation, maintenance, and purchase of services to provide information.

Proposal To Approve Under OMB Delegated authority the Revision of the Following Report

Report title: Capital and Asset Report for Foreign Banking Organizations.

Agency form number: FR Y–7Q.

OMB control number: 7100–0125.[1]

Frequency: Quarterly and annually.

Reporters: Foreign Banking Organizations (FBOs).

Estimated annual reporting hours: FR Y–7Q (quarterly): 763 hours; FR Y–7Q (annually): 65 hours.

Estimated average hours per response: FR Y–7Q (quarterly): 1.75 hours; FR Y–7Q (annually): 1.5 hours.

Number of respondents: FR Y–7Q (quarterly): 109; FR Y–7Q (annually): 43.

General description of report: This information collection is mandatory pursuant to Section 5(c) of the Bank Holding Company Act (12 U.S.C. 1844(c)) and sections 8(c) and 13 of the International Banking Act (12 U.S.C. 3106(c) and 3108)). Overall, the Federal Reserve does not consider these data to be confidential. However, individual respondents may request confidential

[1] Also included in this family of reports are the following reports, which are not being revised: the Financial Statements of U.S. Nonbank Subsidiaries Held by Foreign Banking Organizations (FR Y–7N) and the Abbreviated Financial Statements of U.S. Nonbank Subsidiaries Held by Foreign Banking Organizations (FR Y–7NS).

treatment for any of these reports pursuant to sections (b)(4) and (b)(6) of the Freedom of Information Act (5 U.S.C. 522(b)(4) and (b)(6)). The applicability of these exemptions would need to be determined on a case-by-case basis.

Abstract: The FR Y–7Q collects consolidated regulatory capital information from all FBOs either quarterly or annually. The FR Y–7Q is filed quarterly by FBOs that have effectively elected to become financial holding companies (FHCs) and by FBOs that have total consolidated assets of $50 billion or more, regardless of FHC status. All other FBOs file the FR Y–7Q annually.

Current Actions: The Federal Reserve proposes to collect one new data item to implement the enhanced prudential standards for FBOs adopted pursuant to section 165 of the Dodd-Frank Act (DFA Section 165), Enhanced Prudential Standards for Large Domestic and Foreign Banking Organizations. The new data item, Total U.S. Non-Branch Assets, would be used to determine whether an FBO meets the threshold for formation of a U.S. intermediate holding company. This item would collect the sum of the total combined assets of a top-tier FBO's top-tier U.S. domiciled affiliates.[2] In situations where a top-tier U.S. domiciled affiliate is a parent of one or more subsidiaries, the total consolidated assets of the affiliate would include the assets of the affiliate and its subsidiaries, in accordance with U.S. Generally Accepted Accounting Principles (GAAP), and the total consolidated assets (or total assets, as applicable) of each top-tier U.S. domiciled affiliate should be combined. In situations where a top-tier U.S. domiciled subsidiary is not consolidated with the FBO for GAAP purposes, that entity shall be accounted for under the equity method and the sum of the amount of the investments should be included in the sum of the total combined assets of top-tier U.S. domiciled affiliates. The sum of the total combined assets of top-tier U.S. domiciled affiliates reported by a top-tier FBO should exclude intercompany balances and intercompany transactions between the FBO's U.S. domiciled affiliates to the extent such items are not already eliminated in consolidation. However, the sum of the total combined assets of top-tier U.S. domiciled affiliates reported by a top-tier FBO should include asset exposures to U.S. branches, or agencies of the FBO and to non U.S. domiciled affiliates[3].

U.S. domiciled affiliate is defined as a subsidiary, an associated company, or an entity treated as an associated company (e.g., a corporate joint venture) as set forth in the instructions for the Consolidated Financial Statements for Holding Companies (FR Y–9C;OMB No. 7100–0128). The proposed revision would be effective December 31, 2014.

Board of Governors of the Federal Reserve System, June 12, 2014.

Robert deV. Frierson,

Secretary of the Board.

[FR Doc. 2014–14209 Filed 6–17–14; 8:45 am]

BILLING CODE 6210–01–P

[2] Total combined assets of the top-tier FBO's U.S. domiciled affiliates should exclude the assets of section 2(h)(2) companies as defined in section 2(h)2 of the Bank Holding Company Act (12 U.S.C. 1841(h)(2)) and DPC branch subsidiaries. This item excludes the assets of U.S. branches and agencies.

[3] In cases where the non U.S. Domiciled affiliate is already consolidated with a Top Tier U.S. Domiciled affiliate these exposures are excluded.

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 applications listed below, as well as other related filings required by the Board, are available for immediate inspection at the Federal Reserve Bank indicated. The applications will also be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing on the standards enumerated in the BHC Act (12 U.S.C. 1842(c)). 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 4 of the BHC Act (12 U.S.C. 1843). Unless otherwise noted, nonbanking activities will be conducted throughout the United States.

Unless otherwise noted, comments regarding each of these applications must be received at the Reserve Bank indicated or the offices of the Board of Governors not later than July 14, 2014.

A. Federal Reserve Bank of Atlanta (Chapelle Davis, Assistant Vice President) 1000 Peachtree Street NE., Atlanta, Georgia 30309:

1. *Community & Southern Holdings, Inc.,* Atlanta, Georgia; to merge with Alliance Bancshares, Inc., and thereby acquire Alliance National Bank, both in Dalton, Georgia.

2. *HCBF Holding Company, Inc.,* Fort Peirce, Florida; to merge with Highlands Independent Bancshares, Inc., and thereby acquire Highlands Independent Bank, both in Sebring, Florida.

Board of Governors of the Federal Reserve System, June 13, 2014.

Margaret McCloskey Shanks,

Deputy Secretary of the Board.

[FR Doc. 2014–14218 Filed 6–17–14; 8:45 am]

BILLING CODE 6210–01–P

FEDERAL RESERVE SYSTEM

Notice of Proposals To Engage in or To Acquire Companies Engaged in Permissible Nonbanking Activities

The companies listed in this notice have given notice under section 4 of the Bank Holding Company Act (12 U.S.C. 1843) (BHC Act) and Regulation Y, (12 CFR part 225) to engage *de novo,* or to acquire or control voting securities or assets of a company, including the companies listed below, that engages either directly or through a subsidiary or other company, in a nonbanking activity that is listed in § 225.28 of Regulation Y (12 CFR 225.28) or that the Board has determined by Order to be closely related to banking and permissible for bank holding companies. Unless otherwise noted, these activities will be conducted throughout the United States.

Each notice is available for inspection at the Federal Reserve Bank indicated. The notice also will be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing on the question whether the proposal complies with the standards of section 4 of the BHC Act.

Unless otherwise noted, comments regarding the applications must be received at the Reserve Bank indicated or the offices of the Board of Governors not later than July 3, 2014.

A. Federal Reserve Bank of Minneapolis (Jacquelyn K. Brunmeier, Assistant Vice President) 90 Hennepin Avenue, Minneapolis, Minnesota 55480–0291:

1. *Minnwest Corporation,* Minnetonka, Minnesota; to acquire 100 percent of the voting shares of HiLine Credit Corporation, Morris, Minnesota, by merging it with and into its wholly owned nonbank subsidiary, Minnwest Finance, Inc., Minnetonka, Minnesota,

and thereby engage in extending credit and servicing loans, pursuant to section 225.28(b)(1).

Board of Governors of the Federal Reserve System, June 13, 2014.

Margaret McCloskey Shanks,

Deputy Secretary of the Board.

[FR Doc. 2014–14219 Filed 6–17–14; 8:45 am]

BILLING CODE 6210–01–P

FEDERAL RETIREMENT THRIFT INVESTMENT BOARD

Notice of Sunshine Act Meeting

TIME AND DATE: 10:00 a.m. (Eastern Time) June 23, 2014.

PLACE: 10th Floor Board Meeting Room, 77 K Street NE., Washington, DC 20002.

STATUS: Open to the public.

MATTERS TO BE CONSIDERED:

Open to the Public

1. Approval of the Minutes of the May 19, 2014 Board Member Meeting
2. Monthly Reports
   a. Monthly Participant Activity Report
   b. Monthly Investment Report
   c. Legislative Report
3. Report by the Office of External Affairs

CONTACT PERSON FOR MORE INFORMATION: Kimberly Weaver, Director, Office of External Affairs, (202) 942–1640.

Dated: June 16, 2014.

James Petrick,

General Counsel, Federal Retirement Thrift Investment Board.

[FR Doc. 2014–14349 Filed 6–16–14; 4:15 pm]

BILLING CODE 6760–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the Secretary

[Document Identifier HHS–OS–0990–New—30D]

Agency Information Collection Activities; Submission to OMB for Review and Approval; Public Comment Request

AGENCY: Office of the Secretary, HHS.

ACTION: Notice.

SUMMARY: In compliance with section 3507(a)(1)(D) of the Paperwork Reduction Act of 1995, the Office of the Secretary (OS), Department of Health and Human Services, has submitted an Information Collection Request (ICR), described below, to the Office of Management and Budget (OMB) for review and approval. The ICR is for a new collection. Comments submitted during the first public review of this ICR will be provided to OMB. OMB will accept further comments from the public on this ICR during the review and approval period.

DATES: Comments on the ICR must be received on or before July 18, 2014.

ADDRESSES: Submit your comments to *OIRA_submission@omb.eop.gov* or via facsimile to (202) 395–5806.

FOR FURTHER INFORMATION CONTACT: Information Collection Clearance Officer, *Sherrette.funn@hhs.gov* or (202) 690–6162.

SUPPLEMENTARY INFORMATION: When submitting comments or requesting information, please include the Information Collection Request Title and document identifier HHS–OS–0990–new—30D for reference.

Information Collection Request Title: Education and Training of Healthcare Providers as a Coordinated Public Health Response to Violence Against Women Project.

Abstract: The Office on Women's Health (OWH) is seeking a new clearance to conduct a one year data collection associated with the pilot and evaluation of an eLearning course developed as part of the ''Education and Training of Healthcare Providers as a Coordinated Public Health Response to Violence Against Women Project''. The purpose of this data collection is to gather data from healthcare providers who have volunteered to participate in the pilot and evaluation of an e-learning course designed to educate and train healthcare providers on how to respond to intimate partner violence (IPV) against women. Information obtained from this data collection will be used to identify areas of improvement and measure the effectiveness of the e-learning course in educating healthcare providers about IPV, addressing attitudinal barriers to IPV screening, and increasing IPV screening in clinical practice. This data will also help identify any problems in the navigation and functioning of the e-learning course. The results of this evaluation will assist OWH in making revisions to the course and subsequently coordinating a national launch, making the e-learning course available to healthcare providers across the U.S. All data collection forms and activities will be used within a year time frame.

Need and Proposed Use of the Information: The piloting and evaluation of this eLearning course supports the DHHS and OWH's overall mission and strategic plan. It supports the DHHS objective of implementing ''prevention policies, programming, and interventions to prevent and respond to individuals, families, and communities impacted by domestic violence''. It also enhances OWH's capacity to provide healthcare providers with accurate, evidence-based information and identify innovative educational strategies. Furthermore, the results will also aid in the planning and development of future OWH and other public and private sector initiatives to promote IPV awareness and screening in the healthcare setting. Knowledge gained from the evaluation will inform federal, public, and private sector on how IPV knowledge, attitude, and practices may differ between healthcare providers and healthcare settings.

Likely Respondents: The respondents for this pilot and evaluation are healthcare providers (physicians, nurses, and social workers) who are members of professional associations and who provide services in Nevada, Oklahoma, and South Carolina.

Burden Statement: Burden in this context means the time expended by persons to generate, maintain, retain, disclose or provide the information requested. This includes the time needed to review instructions, to develop, acquire, install and utilize technology and systems for the purpose of collecting, validating and verifying information, processing and maintaining information, and disclosing and providing information, to train personnel and to be able to respond to a collection of information, to search data sources, to complete and review the collection of information, and to transmit or otherwise disclose the information. The total annual burden hours estimated for this ICR are summarized in the table below.

TOTAL ESTIMATED ANNUALIZED BURDEN—HOURS

Form name	Number of respondents	Number of responses per respondent	Average burden per response (in hours)	Total burden hours
Pre-Assessment	1600	1	25/60	667
Post-Assessment	1600	1	25/60	667
Follow-up Assessment	1600	1	25/60	667
Total				2001

Darius Taylor,

Information Collection Clearance Officer.

[FR Doc. 2014–14230 Filed 6–17–14; 8:45 am]

BILLING CODE 4150–05–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Agency Information Collection Activities: Proposed Collection; Comment Request; Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery

AGENCY: U.S. Department of Health and Human Services.

ACTION: 30-Day notice of submission of information collection approval from the Office of Management and Budget and request for comments.

SUMMARY: As part of a Federal Government-wide effort to streamline the process to seek feedback from the public on service delivery, U.S. Department of Health and Human Services has submitted a Generic Information Collection Request (Generic ICR): ''Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery '' to OMB for approval under the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 et. seq.).

DATES: Comments on the ICR must be received on or before July 18, 2014.

ADDRESSES: Submit your comments to *OIRA_submission@omb.eop.gov* or via facsimile to (202) 395–5806.

FOR FURTHER INFORMATION CONTACT: Report Clearance Officer, *Sherrette.Funn@HHS.GOV* or (202) 690–6162.

SUPPLEMENTARY INFORMATION:

Title: Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery

Abstract: The information collection activity will garner qualitative customer and stakeholder feedback in an efficient, timely manner, in accordance with the Administration's commitment to improving service delivery. By qualitative feedback we mean information that provides useful insights on perceptions and opinions, but are not statistical surveys that yield quantitative results that can be generalized to the population of study. This feedback will provide insights into customer or stakeholder perceptions, experiences and expectations, provide an early warning of issues with service, or focus attention on areas where communication, training or changes in operations might improve delivery of products or services. These collections will allow for ongoing, collaborative and actionable communications between the Agency and its customers and stakeholders. It will also allow feedback to contribute directly to the improvement of program management.

Feedback collected under this generic clearance will provide useful information, but it will not yield data that can be generalized to the overall population. This type of generic clearance for qualitative information will not be used for quantitative information collections that are designed to yield reliably actionable results, such as monitoring trends over time or documenting program performance. Such data uses require more rigorous designs that address: the target population to which generalizations will be made, the sampling frame, the sample design (including stratification and clustering), the precision requirements or power calculations that justify the proposed sample size, the expected response rate, methods for assessing potential non-response bias, the protocols for data collection, and any testing procedures that were or will be undertaken prior to fielding the study. Depending on the degree of influence the results are likely to have, such collections may still be eligible for submission for other generic mechanisms that are designed to yield quantitative results.

The Agency received no comments in response to the 60-day notice published in the **Federal Register** of April 3, 2014 (79 FR 18692).

Below we provide U.S. Department of Health and Human Services projected average estimates for the next three years: [1]

Current Actions: Extension of approval for a collection of information.

Type of Review: Extension

Affected Public: Individuals and households, businesses and organizations.

Average Expected Annual Number of activities: 15

Respondents: 200,000 per activity

Annual responses: 3,000,000 annually

Frequency of Response: Once per request

Average minutes per response: 10

Burden hours: 500,000 hours annually

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 Office of Management and Budget control number.

Darius Taylor,

Information Collection Clearance Officer.

[FR Doc. 2014–14187 Filed 6–17–14; 8:45 am]

BILLING CODE 4150–25–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2013–N–1588]

Agency Information Collection Activities; Submission for Office of Management and Budget Review; Comment Request; Tobacco Products, Exemptions From Substantial Equivalence Requirements

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

[1] The 60-day notice included the following estimate of the aggregate burden hours for this generic clearance federal-wide:

Average Expected Annual Number of activities: 15.

Average number of Respondents per Activity: 200,000.

Annual responses: 3,000,000.

Frequency of Response: Once per request.

Average minutes per response: 10.

Burden hours: 500,00 hours annually.

SUMMARY: The Food and Drug Administration (FDA) is announcing that a proposed collection of information has been submitted to the Office of Management and Budget (OMB) for review and clearance under the Paperwork Reduction Act of 1995.

DATES: Fax written comments on the collection of information by July 18, 2014.

ADDRESSES: To ensure that comments on the information collection are received, OMB recommends that written comments be faxed to the Office of Information and Regulatory Affairs, OMB, Attn: FDA Desk Officer, FAX: 202–395–7285, or emailed to *oira_submission@omb.eop.gov*. All comments should be identified with the OMB control number 0910–0684. Also include the FDA docket number found in brackets in the heading of this document.

FOR FURTHER INFORMATION CONTACT: FDA PRA Staff, Office of Operations, Food and Drug Administration, 8455 Colesville Rd., COLE–14526, Silver Spring, MD 20993–0002, *PRAStaff@fda.hhs.gov*.

SUPPLEMENTARY INFORMATION: In compliance with 44 U.S.C. 3507, FDA has submitted the following proposed collection of information to OMB for review and clearance.

Tobacco Products, Exemptions From Substantial Equivalence Requirements—(OMB Control Number 0910–0684)—Extension

On June 22, 2009, the President signed the Family Smoking Prevention and Tobacco Control Act (Tobacco Control Act) (Public Law 111–31) into law. The Tobacco Control Act amended the Federal Food, Drug, and Cosmetic Act (the FD&C Act) by adding a chapter granting FDA important authority to regulate the manufacture, marketing, and distribution of tobacco products to protect the public health generally and to reduce tobacco use by minors.

The FD&C Act, as amended by the Tobacco Control Act, requires that before a new tobacco product may be introduced or delivered for introduction into interstate commerce, a manufacturer must submit a premarket application to FDA, and FDA must issue an order finding that the new product may be introduced or delivered for introduction into interstate commerce (section 910 of the FD&C Act (21 U.S.C. 387j)). An order under section 910 is not required, however, if a manufacturer submits a report under section 905(j) of the FD&C Act (21 U.S.C. 387e(j) demonstrating the new tobacco product's substantial equivalence to an appropriate predicate product, and FDA issues an order finding the new product to be substantially equivalent to the predicate product and in compliance with the requirements of the FD&C Act.

FDA has established a pathway for manufacturers to request exemptions from the substantial equivalence requirements of the FD&C Act in § 1107.1 (21 CFR 1107.1) of the Agency's regulations. As described in § 1107.1(a), FDA may exempt tobacco products that are modified by adding or deleting a tobacco additive, or increasing or decreasing the quantity of an existing tobacco additive, from the requirement of demonstrating substantial equivalence if the Agency determines that: (1) The modification would be a minor modification of a tobacco product; (2) a report demonstrating substantial equivalence is not necessary for the protection of public health; and (3) an exemption is otherwise appropriate.

Section 1107.1(b) states that a request for exemption under section 905(j)(3) of the FD&C Act may be made only by the manufacturer of a legally marketed tobacco product for a minor modification to that tobacco product and that the manufacturer must submit the request and all information supporting it to FDA. The request must be made in an electronic format that FDA can process, review, and archive (or a written request must be made by the manufacturer explaining in detail why the company cannot submit the request in an electronic format and requesting an alternative means of submission to the electronic format).

An exemption request must contain: (1) The manufacturer's address and contact information; (2) identification of the tobacco product(s); (3) a detailed explanation of the purpose for the modification; (4) a detailed description of the modification, including a statement as to whether the modification involves adding or deleting a tobacco additive, or increasing or decreasing the quantity of the existing tobacco additive; (5) a detailed explanation of why the modification is a minor modification of a tobacco product that can be sold under the FD&C Act; (6) a detailed explanation of why a report under section 905(j)(1) of the FD&C Act intended to demonstrate substantial equivalence is not necessary to ensure that permitting the tobacco product to be marketed would be appropriate for protection of the public health; (7) a certification (i.e., a signed statement by a responsible official of the company) summarizing the supporting evidence and providing the rationale for the official's determination that the modification does not increase the tobacco product's appeal to or use by minors, toxicity, addictiveness, or abuse liability; (8) other information justifying an exemption; and (9) an environmental assessment (EA) under part 25 (21 CFR part 25) prepared in accordance with the requirements of § 25.40.

The National Environmental Policy Act (NEPA) (42 U.S.C. 4321–4347) states national environmental objectives and imposes upon each Federal agency the duty to consider the environmental effects of its actions. Section 102(2)(C) of NEPA requires the preparation of an environmental impact statement for every major Federal action that will significantly affect the quality of the human environment.

The FDA NEPA regulations are contained in part 25. All applications for exemption from substantial equivalence require the submission of an EA. An EA provides information that is used to determine whether an FDA action could result in a significant environmental impact. Section 25.40(a) and (c) specifies the content requirements for EAs for nonexcluded actions.

The information required by § 1107.1(b) is submitted to FDA so FDA can determine whether an exemption from substantial equivalence to the product is appropriate for the protection of the public health. Section 1107.1(c) states that FDA will review the information submitted and determine whether to grant or deny an exemption based on whether the criteria in section 905(j)(3) of the FD&C Act are met. FDA may request additional information if necessary to make a determination and may consider the exemption request withdrawn if the information is not provided within the requested timeframe.

Section 1107.1(d) provides that FDA may rescind an exemption where necessary to protect the public health.

Section 905(j)(1)(A)(ii) of the FD&C Act states that if an exemption has been requested and granted, a report must be submitted to FDA that demonstrates that the tobacco product is modified within the meaning of section 905(j)(3), the modifications are to a product that is commercially marketed and in compliance with the requirements of the FD&C Act, and all of the modifications are covered by exemptions granted by the Secretary pursuant to section 905(j)(3).

In the **Federal Register** of December 19, 2013 (78 FR 76838), FDA published a 60-day notice requesting public comment on the proposed collection of

information. Six comment submissions were received, some of which included multiple comments.

(Comment) Regarding the clarity of information collected, several comments indicated some confusion between the information being collected and the information needed to support an exemption request.

(Response) Section 1107.1(a) sets out the general requirements for requesting an exemption, but a manufacturer will need to determine how to meet the requirements for any of its new products that use the pathway. FDA intends to consider issuing a regulation or guidance to further clarify terms as experience is gained with the pathway.

(Comment) A few comments questioned the quality of the information being requested.

(Response) We disagree that the information required in an exemption request is not sufficient. We believe the information requested is what FDA needs to make a determination on an exemption request. Furthermore, several commenters also agreed with the sufficiency of the information needed to support an exemption request.

(Comment) Many comments addressed the accuracy of FDA's estimate of the burden for requesting a modification to an exemption request and questioned whether this burden was underestimated. Additionally, there was reference to the submittal of duplicative information.

(Response) FDA disagrees with these comments. We believe the burden estimates are appropriate and reflect the information needed by FDA when reviewing an exemption request. FDA also disagrees that there is duplicative information requested. The regulations implement the requirements of the FD&C Act for the exemption pathway to market. The commenters may be referring to the other notification and reporting requirements related to additives, such as those in section 904(c) of the FD&C Act (21 U.S. C. 387d(c)), but those requirements are not in the scope of this information collection.

FDA estimates the burden of this collection of information as follows:

TABLE 1—ESTIMATED ANNUAL REPORTING BURDEN [1]

Activity	Number of respondents	Number of responses per respondent	Total annual responses	Average burden per response (in hours)	Total hours
21 CFR 1107.1(b): Preparation of tobacco product exemption from substantial equivalence request	500	1	500	12	6,000
21 CFR 1107.1(c): Preparation of additional information for tobacco product exemption from substantial equivalence request	150	1	150	3	450
21 CFR 25.40: Preparation of an environmental assessment	500	1	500	12	6,000
Section 905(j)(1)(A)(ii) of the FD&C Act: If exemption granted, report submitted to demonstrate tobacco product is modified under section 905(j)(3), modifications are to a product that is commercially marketed and compliant product, and modifications covered by exemptions granted by Secretary pursuant to section 905(j)(3)	750	1	750	3	2,250
Total					14,700

[1] There are no capital costs or operating and maintenance costs associated with this collection of information.

FDA estimates that 500 requests for exemption will be submitted annually, and that it will take approximately 12 hours to prepare an exemption request. FDA also estimates that up to 30 percent (150) of the initial requests for information may require additional information in support of the initial exemption request, and it is expected that it will take an average of 3 hours to prepare the additional information. FDA also estimates that 750 manufacturers will take approximately 12 hours to prepare and submit an EA under part 25 in accordance with the requirements of § 25.40, as referenced in § 1107.1(b)(9).

FDA estimates that 750 respondents will take 3 hours to prepare a report under section 905(j)(1)(A)(ii) of the FD&C Act, which requires a manufacturer to submit a report at least 90 days prior to making an introduction or delivery into interstate commerce for commercial distribution of a tobacco product. The report will contain the manufacturer's basis that the tobacco product is modified within the meaning of section 905(j)(3) of the FD&C Act, the modifications are to a product that is commercially marketed and compliant with the FD&C Act, the modifications are covered by exemptions granted pursuant to section 905(j)(3), and a listing of actions taken to comply with any applicable requirements of section 907 of the FD&C Act (21 U.S.C. 387g). FDA's estimates are based on experience with and information on other FDA-regulated products and indications from industry.

Dated: June 11, 2014.

Leslie Kux,

Assistant Commissioner for Policy.

[FR Doc. 2014–14253 Filed 6–17–14; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2013–N–1439]

Agency Information Collection Activities; Announcement of Office of Management and Budget Approval; Adverse Event Program for Medical Devices (Medical Product Safety Network)

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing that a collection of information entitled ''Adverse Event Program for Medical Devices (Medical Product Safety Network (MedSun))'' has been approved by the Office of Management and

Budget (OMB) under the Paperwork Reduction Act of 1995.

FOR FURTHER INFORMATION CONTACT: FDA PRA Staff, Office of Operations, Food and Drug Administration, 8455 Colesville Rd., COLE–14526, Silver Spring, MD 20993–0002 *PRAStaff@fda.hhs.gov.*

SUPPLEMENTARY INFORMATION: On April 22, 2014, the Agency submitted a proposed collection of information entitled ''Adverse Event Program for Medical Devices (Medical Product Safety Network (MedSun))'' to OMB for review and clearance under 44 U.S.C. 3507. 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. OMB has now approved the information collection and has assigned OMB control number 0910–0471. The approval expires on May 31, 2017. A copy of the supporting statement for this information collection is available on the Internet at *http://www.reginfo.gov/public/do/PRAMain.*

Dated: June 12, 2014.

Leslie Kux,

Assistant Commissioner for Policy.

[FR Doc. 2014–14252 Filed 6–17–14; 8:45 am]

BILLING CODE 4164–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2014–D–0397]

Draft Guidance for Industry on Internet/Social Media Platforms With Character Space Limitations: Presenting Risk and Benefit Information for Prescription Drugs and Medical Devices; Availability

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA or Agency) is announcing the availability of a draft guidance for industry entitled ''Internet/Social Media Platforms with Character Space Limitations: Presenting Risk and Benefit Information for Prescription Drugs and Medical Devices.'' This draft guidance responds to, among other things, stakeholder requests for specific guidance and describes FDA's current thinking on how manufacturers, packers, and distributors (firms) of prescription human and animal drugs (drugs) and medical devices for human use (devices), including biological products, that choose to present benefit information should present both benefit and risk information within advertising and promotional labeling of their FDA-regulated medical products on electronic/digital platforms that are associated with character space limitations, specifically on the Internet and through social media or other technological venues (Internet/social media). The draft guidance represents FDA's current thinking on specific aspects of FDA's evolving consideration of social media platforms and other Internet-related matters. FDA continues actively to review, analyze, and develop approaches to a variety of topics related to the labeling and advertising of medical products, including the development of this and other guidance addressing the use of social media platforms and the Internet.

DATES: Although you can comment on any guidance at any time (see 21 CFR 10.115(g)(5)), to ensure that the Agency considers your comments on this draft guidance before it begins work on the final version of the guidance, submit either electronic or written comments on the draft guidance by September 16, 2014.

ADDRESSES: Submit written requests for single copies of the draft guidance to the Division of Drug Information, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 51, Rm. 2201, Silver Spring, MD 20993–0002; or to the Office of Communication, Outreach and Development, Center for Biologics Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 71, Rm. 3128, Silver Spring, MD 20993–0002; or to the Office of the Center Director, Guidance and Policy Development, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 66, Rm. 5431, Silver Spring, MD 20993–0002. Send one self-addressed adhesive label to assist that office in processing your requests. See the **SUPPLEMENTARY INFORMATION** section for electronic access to the draft guidance document.

Submit electronic comments on the draft guidance to *http://www.regulations.gov.* Submit written comments to the Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

FOR FURTHER INFORMATION CONTACT:

Regarding human prescription drugs: Jean-Ah Kang, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 51, Silver Spring, MD 20993, 301–796–1200.

Regarding prescription human biological products: Stephen Ripley, Center for Biologics Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 71, Rm. 7301, Silver Spring, MD 20993–0002, 240–402–7911.

Regarding animal prescription drugs: Dorothy McAdams, Center for Veterinary Medicine (HFV–216), Food and Drug Administration, 7519 Standish Pl., Rockville, MD 20855, 240–276–9300.

Regarding medical devices for human use: Deborah Wolf, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 66, Silver Spring, MD 20993, 301–796–5732.

SUPPLEMENTARY INFORMATION:

I. Background

FDA is announcing the availability of a draft guidance for industry entitled ''Internet/Social Media Platforms with Character Space Limitations: Presenting Risk and Benefit Information for Prescription Drugs and Medical Devices.''

On November 12 and 13, 2009, FDA held a public hearing entitled ''Promotion of Food and Drug Administration—Regulated Medical Products Using the Internet and Social Media Tools'' to provide an opportunity for broad public participation and comment on the following questions that relate specifically to promotional issues:

1. For what online communications are manufacturers, packers, or distributors accountable?
2. How can manufacturers, packers, or distributors fulfill regulatory requirements (e.g., fair balance, disclosure of indication and risk information, and postmarketing submission requirements) in their internet and social media promotion, particularly when using tools that are associated with space limitations and tools that allow for real-time communications (e.g., microblogs and mobile technology)?
3. What parameters should apply to the posting of corrective information on Web sites controlled by third parties?
4. When is the use of links appropriate?

Subsequent to the live testimony heard at the public hearing, FDA received 72 comments to the docket.

Specifically, this draft guidance presents considerations to illustrate FDA's thinking on factors that are relevant to the communication of benefit and risk information on Internet/social media platforms with character space limitations. Examples of Internet/

social media platforms with character space limitations include online microblog messaging (e.g., messages on Twitter or ''tweets,'' which are currently limited to 140 character spaces per tweet) and online paid search (e.g., sponsored links on search engines such as Google and Yahoo, which have limited character spaces as well as other platform-imposed considerations).

Please note that this draft guidance does not address promotion via product Web sites, Web pages on social media networking platforms (e.g., individual product pages on Web sites such as Facebook, Twitter, YouTube), and online Web banners as the Agency believes that these specific types of Internet/social media platforms do not impose the same character space constraints as online microblog messaging and online paid search. This draft guidance also does not address responsive Web design or other technology-specific layout features that may result in product promotion presentations that differ depending on the technology used to view them (e.g., desktop computer monitors, mobile devices, tablets).

This draft guidance is being issued consistent with FDA's good guidance practices regulation (21 CFR 10.115). The draft guidance, when finalized, will represent the Agency's current thinking on presenting risk and benefit information for prescription drugs and medical devices on Internet/social media platforms with character space limitations. It does not create or confer any rights for or on any person and does not operate to bind FDA or the public. An alternative approach may be used if such approach satisfies the requirements of the applicable statutes and regulations.

II. The Paperwork Reduction Act of 1995

This draft guidance contains information collection provisions that are subject to review by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3501–3520). The collections of information in 21 CFR 202.1 and 21 CFR parts 801 and 809 have been approved under OMB control numbers 0910–0686 and 0910–0485, respectively. In accordance with the PRA, prior to publication of any final guidance document, FDA intends to solicit public comment and obtain OMB approval for any information collections recommended in this guidance that are new or that would represent material modifications to previously approved collections of information found in FDA regulations or guidances.

III. Comments

Interested persons may submit either electronic comments regarding this document to *http://www.regulations.gov* or written comments to the Division of Dockets Management (see **ADDRESSES**). It is only necessary to send one set of comments. Identify comments with the docket number found in brackets in the heading of this document. Received comments may be seen in the Division of Dockets Management between 9 a.m. and 4 p.m., Monday through Friday, and will be posted to the docket at *http://www.regulations.gov.*

IV. Electronic Access

Persons with access to the Internet may obtain the document at *http://www.fda.gov/Drugs/GuidanceComplianceRegulatoryInformation/Guidances/default.htm*, *http://www.fda.gov/BiologicsBloodVaccines/GuidanceComplianceRegulatoryInformation/default.htm*, *http://www.fda.gov/AnimalVeterinary/GuidanceComplianceEnforcement/GuidanceforIndustry/default.htm*, *http://www.fda.gov/MedicalDevices/deviceregulationandguidance/guidancedocuments/default.htm*, or *http://www.regulations.gov.*

Dated: June 13, 2014.

Leslie Kux,

Assistant Commissioner for Policy.

[FR Doc. 2014–14220 Filed 6–17–14; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2014–D–0447]

Draft Guidance for Industry on Internet/Social Media Platforms: Correcting Independent Third-Party Misinformation About Prescription Drugs and Medical Devices; Availability

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA or Agency) is announcing the availability of a draft guidance for industry entitled ''Internet/Social Media Platforms: Correcting Independent Third-Party Misinformation About Prescription Drugs and Medical Devices.'' This draft guidance responds to (among other things) stakeholder requests for specific guidance and describes FDA's current thinking on how manufacturers, packers, and distributors (firms) of prescription human and animal drugs (drugs) and medical devices for human use (devices), including biological products, should respond, if they choose to respond, to misinformation related to a firm's own FDA-approved or cleared products when that information is created or disseminated by independent third parties. This draft guidance updates and clarifies FDA's policies on the correction of misinformation created or disseminated by independent third parties on the Internet or through social media platforms, regardless of whether that misinformation appears on a firm's own forum or an independent third-party forum or Web site. The draft guidance represents FDA's current thinking on specific aspects of FDA's evolving consideration of social media platforms and other Internet-related matters. FDA continues actively to review, analyze, and develop approaches to a variety of topics related to the labeling and advertising of medical products, including the development of this and other guidance addressing the use of social media platforms and the Internet.

DATES: Although you can comment on any guidance at any time (see 21 CFR 10.115(g)(5)), to ensure that the Agency considers your comments on this draft guidance before it begins work on the final version of the guidance, submit either electronic or written comments on the draft guidance by September 16, 2014. Submit written comments on the proposed collection of information by August 18, 2014.

ADDRESSES: Submit written requests for single copies of the draft guidance to the Division of Drug Information, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 51, Rm. 2201, Silver Spring, MD 20993–0002; to the Office of Communication, Outreach and Development, Center for Biologics Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 71, Rm. 3128, Silver Spring, MD 20993–0002; to the Communications Staff (HFV–12), Center for Veterinary Medicine, Food and Drug Administration, 7519 Standish Pl., Rockville, MD 20855; or to the Office of the Center Director, Guidance and Policy Development, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 66, Rm. 5431, Silver Spring, MD 20993–0002. Send one self-addressed adhesive label to assist that office in processing your requests. See the **SUPPLEMENTARY INFORMATION** section

for electronic access to the draft guidance document.

Submit electronic comments on the draft guidance to *http://www.regulations.gov.* Submit written comments to the Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

FOR FURTHER INFORMATION CONTACT:

Regarding human prescription drugs: Julie Chronis, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 51, Silver Spring, MD 20993–0002, 301–796–1200.

Regarding human prescription biological products: Stephen Ripley, Center for Biologics Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 71, Rm. 7301, Silver Spring, MD 20993–0002, 240–402–7911.

Regarding animal prescription drugs: Thomas Moskal, Center for Veterinary Medicine (HFV–216), Food and Drug Administration, 7519 Standish Pl., Rockville, MD 20855, 240–276–9300.

Regarding medical devices for human use: Deborah Wolf, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 66, Rm. 3414, Silver Spring, MD 20993–0002, 301–796–5732.

SUPPLEMENTARY INFORMATION:

I. Background

FDA is announcing the availability of a draft guidance for industry entitled ''Internet/Social Media Platforms: Correcting Independent Third-Party Misinformation About Prescription Drugs and Medical Devices.'' On November 12–13, 2009, FDA held a public hearing entitled ''Promotion of Food and Drug Administration-Regulated Medical Products Using the Internet and Social Media Tools'' to provide an opportunity for broad public participation and comment on the following questions that relate specifically to promotional issues:

1. For what online communications are manufacturers, packers, or distributors accountable?

2. How can manufacturers, packers, or distributors fulfill regulatory requirements (e.g., fair balance, disclosure of indication and risk information, and postmarketing submission requirements) in their Internet and social media promotion, particularly when using tools that are associated with space limitations and tools that allow for real-time communications (e.g., microblogs and mobile technology)?

3. What parameters should apply to the posting of corrective information on Web sites controlled by third parties?

4. When is the use of links appropriate?

Subsequent to the live testimony heard at the public hearing, FDA received 72 comments to the docket.

This draft guidance provides FDA's recommendations regarding how manufacturers, packers, and distributors of prescription human and animal drugs and medical devices for human use, including biological products, should respond, if they choose to respond, to misinformation created or disseminated by independent third parties related to a firm's own FDA-approved or cleared products on the Internet or through social media platforms.

This draft guidance provides FDA's recommendations to firms that voluntarily choose to correct misinformation that appears on the Internet or through social media platforms. This draft guidance discusses the type of information that is considered misinformation, recommends parameters for corrective information, and recommends approaches to correcting misinformation. It refers only to misinformation that is created or disseminated by an independent third party and that is not produced by, or on behalf of, or prompted by the firm in any particular. When a firm chooses to correct misinformation in a truthful and non-misleading manner and according to the recommendations in this draft guidance, FDA does not intend to object if the corrective information voluntarily provided by the firm does not satisfy otherwise applicable regulatory requirements regarding labeling or advertising, if any. If a firm chooses to respond to misinformation about its products using non-truthful or misleading information or in a manner other than that recommended in this draft guidance, however, FDA may object if the information provided by the firm does not comply with applicable regulatory requirements related to labeling or advertising, if any.

This draft guidance is being issued consistent with FDA's good guidance practices regulation (21 CFR 10.115). The draft guidance, when finalized, will represent the Agency's current thinking on correcting misinformation created or disseminated by independent third parties. It does not create or confer any rights for or on any person and does not operate to bind FDA or the public. An alternative approach may be used if such approach satisfies the requirements of the applicable statutes and regulations.

II. The Paperwork Reduction Act of 1995

Under the Paperwork Reduction Act of 1995 (the PRA) (44 U.S.C. 3501–3520), Federal agencies must obtain approval from the Office of Management and Budget (OMB) for each collection of information they conduct or sponsor. ''Collection of information'' is defined in 44 U.S.C. 3502(3) and 5 CFR 1320.3(c) and includes Agency requests or requirements that members of the public submit reports, keep records, or provide information to a third party. Section 3506(c)(2)(A) of the PRA (44 U.S.C. 3506(c)(2)(A)) requires Federal agencies to provide a 60-day notice in the **Federal Register** concerning each proposed collection of information before submitting the collection to OMB for approval. To comply with this requirement, FDA is publishing notice of the proposed collection of information set forth in this document.

With respect to the following collection of information, FDA invites comments on these topics: (1) Whether the proposed collection of information is necessary for the proper performance of FDA's functions, including whether the information will have practical utility; (2) the accuracy of FDA's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used; (3) ways to enhance the quality, utility, and clarity of the information collected; and (4) ways to minimize the burden of information collected on the respondents, including through the use of automated collection techniques, when appropriate, and other forms of information technology.

Title: Internet/Social Media Platforms: Correcting Independent Third-Party Misinformation About Prescription Drugs and Medical Devices.

Description of Respondents: Respondents to this collection of information are manufacturers, packers, and distributors (firms) of prescription human and animal drugs and medical devices for human use, including biological products.

Burden Estimate: The draft guidance pertains to the correction of misinformation created or disseminated by independent third parties related to a firm's own FDA-approved or -cleared products on the Internet or through social media platforms.

The draft guidance explains FDA's current policy position that a firm may voluntarily correct misinformation about its own FDA-approved or -cleared products that is created or disseminated by independent third parties who are not under the firm's control or

influence. If a firm does so in a truthful and non-misleading manner and in accordance with the recommendations in the draft guidance, FDA does not intend to object if the corrective information voluntarily provided by the firm does not satisfy otherwise applicable regulatory requirements related to labeling and advertising, if any.

Because the draft guidance recommends that a firm disclose certain information to others when correcting misinformation created or disseminated by independent third parties, this ''third-party disclosure'' constitutes a ''collection of information'' under the PRA. In addition, the PRA is triggered because the draft guidance also recommends that a firm maintain certain records related to this disclosure—the content of the misinformation, where the misinformation appeared, the date the misinformation appeared or was located, the corrective information that was provided, and the date the corrective information was provided.

Specifically, the draft guidance recommends that firms provide appropriate truthful and non-misleading corrective information, or alternatively, it may provide a reputable source from which to obtain the correct information. For the purposes of the draft guidance, to be considered ''appropriate corrective information,'' a firm's communication should:

- Be relevant and responsive to the misinformation;
- Be limited and tailored to the misinformation;
- Be non-promotional in nature, tone, and presentation;
- Be accurate;
- Be consistent with the FDA-required labeling for the product;
- Be supported by sufficient evidence, including substantial evidence, when appropriate, for prescription drugs;
- Either be posted in conjunction with the misinformation in the same area or forum (if posted directly to the forum by the firm), or should reference the misinformation and be intended to be posted in conjunction with the misinformation (if provided to the forum operator or author); and
- Disclose that the person providing the corrective information is affiliated with the firm that manufactures, packs, or distributes the product.

The FDA-required labeling should be included or provided in a readily accessible format. (As two examples, a firm may provide a link that goes directly to the FDA-required labeling or may provide a link that opens a new window to a portable document format (PDF) file.)

The draft guidance also recommends that a firm correct all the misinformation in one clearly defined portion of a forum, but it is not expected to correct each occurrence of independent third-party misinformation throughout an entire forum. When a firm decides to correct all the misinformation in one clearly defined portion of a forum, the firm should clearly identify the misinformation it is correcting, define the portion of the forum it is correcting, describe the location or the nature of the misinformation that was corrected, and provide a date the correction is made.

A firm may provide the correct information to the independent author for the author to incorporate or request the author remove the misinformation or allow comments to be posted. The firm may request that the site administrator remove the misinformation or allow comments to be posted.

FDA estimates that approximately 400 firms annually undertake correcting 50 pieces of misinformation created or disseminated by independent third parties on the Internet or through social media. FDA estimates that it will take firms approximately 3 hours to correct misinformation as recommended in the draft guidance.

FDA also estimates that approximately 20,000 records will be maintained by firms that have chosen to correct misinformation created or disseminated by independent third parties on the Internet or through social media and that each record will take approximately 30 minutes to prepare and maintain.

TABLE 1—ESTIMATED ANNUAL RECORDKEEPING BURDEN [1]

Draft guidance on correcting independent third-party misinformation	Number of recordkeepers	Number of records per recordkeeper	Total annual records	Hours per record	Total hours
Records related to the correction of independent third-party misinformation.	400	50	20,000	0.5 (30 minutes)	10,000

[1] There are no capital costs or operating and maintenance costs associated with this collection of information.

TABLE 2—ESTIMATED ANNUAL THIRD-PARTY DISCLOSURE BURDEN [1]

Draft guidance on correcting independent hird-party misinformation	Number of respondents	Number of disclosures per respondent	Total annual disclosures	Hours per disclosure	Total hours
Corrections of independent third-party misinformation	400	50	20,000	3	60,000

[1] There are no capital costs or operating and maintenance costs associated with this collection of information.

III. Comments

In addition to general comments, FDA specifically requests comments on the following issue: The draft guidance recommends that a firm should identify the misinformation or define the portion of the forum it is correcting and should correct all the misinformation that appears in that clearly defined portion. Is this an appropriate and effective way for firms to correct misinformation without correcting all misinformation that might appear in a forum? When or under what conditions should a sponsor choose a specific portion of a forum to correct? What factors, such as the platform(s) or technology(ies) that can be used to view the forum, the relative location of pieces of misinformation the firm chooses to correct, the nature of the forum, the quantity of information, and the length of time the forum encompasses, should be taken into account in choosing the portion of a forum to correct?

Interested persons may submit either electronic comments regarding this

document to *http://www.regulations.gov* or written comments to the Division of Dockets Management (see **ADDRESSES**). It is only necessary to send one set of comments. Identify comments with the docket number found in brackets in the heading of this document. Received comments may be seen in the Division of Dockets Management between 9 a.m. and 4 p.m., Monday through Friday, and will be posted to the docket at *http://www.regulations.gov.*

IV. Electronic Access

Persons with access to the Internet may obtain the document at *http://www.fda.gov/Drugs/GuidanceComplianceRegulatoryInformation/Guidances/default.htm*, *http://www.fda.gov/BiologicsBloodVaccines/GuidanceComplianceRegulatoryInformation/default.htm*, *http://www.fda.gov/AnimalVeterinary/GuidanceComplianceEnforcement/GuidanceforIndustry/default.htm*, *http://www.fda.gov/MedicalDevices/DeviceRegulationandGuidance/GuidanceDocuments/default.htm*, or *http://www.regulations.gov.*

Dated: June 13, 2014.

Leslie Kux,

Assistant Commissioner for Policy.

[FR Doc. 2014–14221 Filed 6–17–14; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2014–P–0231]

Medical Devices; Exemption From Premarket Notification: Wheelchair Elevator

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing that it has received a petition requesting exemption from the premarket notification requirements for a wheelchair elevator device commonly known as a manually operated portable wheelchair lift. This device is used to provide a means for a disabled person to move a wheelchair from one level to another. FDA is publishing this notice to obtain comments in accordance with procedures established by the Food and Drug Administration Modernization Act of 1997 (FDAMA).

DATES: Submit either electronic or written comments by July 18, 2014.

ADDRESSES: You may submit comments, identified by Docket No. FDA–2014–P–0231, by any of the following methods:

Electronic Submissions

Submit electronic comments in the following way:

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

Written Submissions

Submit written submissions in the following way:

• Mail/Hand delivery/Courier (for paper submissions): Division of Dockets Management (HFA–305), Food and Drug Administration, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

Instructions: All submissions received must include the Agency name and Docket No. FDA–2014–P–0231 for this notice. All comments received may be posted without change to *http://www.regulations.gov,* including any personal information provided. For additional information on submitting comments, see the ''Comments'' heading of the **SUPPLEMENTARY INFORMATION** section of this document.

Docket: For access to the docket to read background documents or comments received, go to *http://www.regulations.gov* 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 Division of Dockets Management, 5630 Fishers Lane, Rm. 1061, Rockville, MD 20852.

FOR FURTHER INFORMATION CONTACT: Michael J. Ryan, Center for Devices and Radiological Health, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 66, Rm. 1615, Silver Spring, MD 20993–0002, 301–796–6283, *michael.ryan@fda.hhs.gov*.

SUPPLEMENTARY INFORMATION:

I. Statutory Background

Under section 513 of the Federal Food, Drug, and Cosmetic Act (the FD&C Act) (21 U.S.C. 360c), FDA must classify devices into one of three regulatory classes: Class I, class II, or class III. FDA classification of a device is determined by the amount of regulation necessary to provide a reasonable assurance of safety and effectiveness. Under the Medical Device Amendments of 1976 (1976 amendments) (Public Law 94–295), as amended by the Safe Medical Devices Act of 1990 (Public Law 101–629), devices are to be classified into class I (general controls) if there is information showing that the general controls of the FD&C Act are sufficient to assure safety and effectiveness; into class II (special controls) if general controls, by themselves, are insufficient to provide reasonable assurance of safety and effectiveness, but there is sufficient information to establish special controls to provide such assurance; and into class III (premarket approval) if there is insufficient information to support classifying a device into class I or class II and the device is a life sustaining or life supporting device, or is for a use which is of substantial importance in preventing impairment of human health or presents a potential unreasonable risk of illness or injury.

Most generic types of devices that were on the market before the date of the 1976 amendments (May 28, 1976) (generally referred to as preamendments devices) have been classified by FDA under the procedures set forth in section 513(c) and (d) of the FD&C Act through the issuance of classification regulations into one of these three regulatory classes. Devices introduced into interstate commerce for the first time on or after May 28, 1976 (generally referred to as postamendments devices), are classified through the premarket notification process under section 510(k) of the FD&C Act (21 U.S.C. 360(k). Section 510(k) of the FD&C Act and the implementing regulations, 21 CFR part 807, require persons who intend to market a new device to submit a premarket notification (510(k)) containing information that allows FDA to determine whether the new device is ''substantially equivalent'' within the meaning of section 513(i) of the FD&C Act to a legally marketed device that does not require premarket approval.

On November 21, 1997, the President signed into law FDAMA (Public Law 105–115). Section 206 of FDAMA, in part, added a new section, 510(m), to the FD&C Act. Section 510(m)(1) of the FD&C Act requires FDA, within 60 days after enactment of FDAMA, to publish in the **Federal Register** a list of each type of class II device that does not require a report under section 510(k) of the FD&C Act to provide reasonable assurance of safety and effectiveness. Section 510(m) of the FD&C Act further provides that a 510(k) will no longer be required for these devices upon the date of publication of the list in the **Federal Register**. FDA published that list in the **Federal Register** of January 21, 1998 (63 FR 3142).

Section 510(m)(2) of the FD&C Act provides that 1 day after date of publication of the list under section 510(m)(1), FDA may exempt a device on its own initiative or upon petition of an interested person if FDA determines that a 510(k) is not necessary to provide reasonable assurance of the safety and

effectiveness of the device. This section requires FDA to publish in the **Federal Register** a notice of intent to exempt a device, or of the petition, and to provide a 30-day comment period. Within 120 days of publication of this document, FDA must publish in the **Federal Register** its final determination regarding the exemption of the device that was the subject of the notice. If FDA fails to respond to a petition under this section within 180 days of receiving it, the petition shall be deemed granted.

II. Criteria for Exemption

There are a number of factors FDA may consider to determine whether a 510(k) is necessary to provide reasonable assurance of the safety and effectiveness of a class II device. These factors are discussed in the guidance the Agency issued on February 19, 1998, entitled ''Procedures for Class II Device Exemptions from Premarket Notification, Guidance for Industry and CDRH Staff.'' That guidance is available through the Internet at *http://www.fda.gov/downloads/MedicalDevices/DeviceRegulationandGuidance/GuidanceDocuments/UCM080199.pdf*. Send an email request to *dsmica@fda.hhs.gov* to receive an electronic copy of the document or send a fax request to 301–847–8149 to receive a hard copy. Please use the document number 159 to identify the guidance you are requesting.

III. Proposed Class II Device Exemptions

FDA has received the following petition requesting an exemption from premarket notification for a class II device: Dave Smith, on behalf of Adaptive Engineering, Inc., for its wheelchair elevator device (commonly known as a manually operated portable wheelchair lift), classified under 21 CFR 890.3930.

IV. Comments

Interested persons may submit either electronic comments regarding this document to *http://www.regulations.gov* or written comments to the Division of Dockets Management (see **ADDRESSES**). It is only necessary to send one set of comments. Identify comments with the docket number found in brackets in the heading of this document. Received comments may be seen in the Division of Dockets Management between 9 a.m. and 4 p.m., Monday through Friday.

Dated: June 12, 2014.

Leslie Kux,

Assistant Commissioner for Policy.

[FR Doc. 2014–14215 Filed 6–17–14; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Health Resources and Services Administration

Agency Information Collection Activities: Proposed Collection: Public Comment Request

AGENCY: Health Resources and Services Administration, HHS.

ACTION: Notice.

SUMMARY: In compliance with the requirement for opportunity for public comment on proposed data collection projects (Section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995), the Health Resources and Services Administration (HRSA) announces plans to submit an Information Collection Request (ICR), described below, to the Office of Management and Budget (OMB). Prior to submitting the ICR to OMB, HRSA seeks comments from the public regarding the burden estimate, below, or any other aspect of the ICR.

DATES: Comments on this Information Collection Request must be received no later than August 18, 2014.

ADDRESSES: Submit your comments to *paperwork@hrsa.gov* or mail the HRSA Information Collection Clearance Officer, Room 10–29, Parklawn Building, 5600 Fishers Lane, Rockville, MD 20857.

FOR FURTHER INFORMATION CONTACT: To request more information on the proposed project or to obtain a copy of the data collection plans and draft instruments, email *paperwork@hrsa.gov* or call the HRSA Information Collection Clearance Officer at (301) 443–1984.

SUPPLEMENTARY INFORMATION: When submitting comments or requesting information, please include the information request collection title for reference.

Information Collection Request Title: AIDS Drug Assistance Program Data Report OMB No. 0915–0345—Revision

Abstract: HRSA's AIDS Drug Assistance Program (ADAP) is funded through The Ryan White HIV/AIDS Program, Part B, Title XXVI of the Public Health Service Act, which provides grants to states and territories. ADAP provides medications for the treatment of HIV/AIDS. Program funds may also be used to purchase health insurance for eligible clients and for services that enhance access, adherence, and monitoring of drug treatments.

Each of the 50 states, the District of Columbia, Puerto Rico, and several territories receive ADAP grants. As part of the funding requirements, ADAPs submit reports concerning information on patients served, eligibility requirements, pharmaceuticals prescribed, pricing and other sources of support to provide AIDS medication treatment, cost data, and coordination with Medicaid. Since 2005, ADAPs have supplied aggregate data to HRSA using the ADAP Quarterly Report (AQR). However, aggregate data cannot be analyzed with the detail that is required to assess quality of care or to sufficiently account for the use of Ryan White HIV/AIDS Program Funds. To address this limitation, HRSA's HIV/AIDS Bureau (HAB) developed a client-level data system for ADAPs called the ADAP Data Report (ADR), and in 2013 ADAPs began submitting the ADR. As of April 30, 2014, HAB retired the AQR and now only requires the submission of the ADR. The ADR will be submitted annually and consists of a Grantee Report and a client-level data file.

Need and Proposed Use of the Information: The Ryan White HIV/AIDS Program requires the submission of annual reports by the Secretary of the Department of Health and Human Services (HHS) to the appropriate committees of Congress. The collection of grantee-level and client-level data enables HRSA to more effectively respond to requests from the Secretary of HHS. In addition, client-level information is needed by HRSA in order to respond to the request for reviews of program performance and information for strategic planning. Client-level data is also needed to support the implementation and monitoring of the National HIV/AIDS Strategy (NHAS).

On April 11, 2012, a memo from the Secretary of HHS directed HRSA with other HHS Operating Divisions (OpDivs) to work together to: (1) Identify seven common core HIV/AIDS indicators; (2) develop implementation plans to deploy these indicators; and (3) streamline data collection and reduce reporting by at least 20 to 25 percent. In November 2012, the HIV/AIDS Indicators Implementation Group (HAIIG), comprised of representatives from HHS OpDivs, the Department of Housing and Urban Development, the Veterans' Health Administration, and community partners successfully identified the required common core HIV/AIDS indicators.

Revisions to the ADR are required to support implementation of the core

indicators, streamline data collection, and reduce the reporting burden. Eleven data elements will be deleted from the ADR and several variables were modified to reduce reporting burden. *Sex at Birth,* defined to the biological sex assigned to the client at birth, will be added to align with variables collected by other HHS OpDivs. *Type of ADAP-funded insurance assistance received,* will also be added to track ADAP's payment of full or partial premium, co-pays, and deductibles.

In addition to the new data elements noted above, other new variables will be added to the ADR to address provisions set forth in Section 4302 of the Affordable Care Act (ACA). The ACA includes several provisions aimed at eliminating health disparities in America. Section 4302 (Understanding health disparities: Data collection and analysis) of the ACA focuses on the standardization, collection, analysis, and reporting of health disparities data. Section 4302 requires the Secretary of DHHS to establish data collection standards for race, ethnicity, and sex. The race/ethnicity data elements include reporting of Hispanic, Asian, and Native Hawaiian/Pacific Islander subgroups. The categories for HHS data standards for race and ethnicity are based on the disaggregation of the OMB standard used in the American Community Survey (ACS) and the 2000 and 2010 Decennial Census. The subgroup categories can be rolled-up to the OMB standard. These new data elements will be used in data analysis intended to identify and understand health disparities.

Likely Respondents: State ADAPs of Ryan White Part B grantees.

Burden Statement: Burden in this context means the time expended by persons to generate, maintain, retain, disclose or provide the information requested. This includes the time needed to review instructions; to develop, acquire, install and utilize technology and systems for the purpose of collecting, validating and verifying information, processing and maintaining information, and disclosing and providing information; to train personnel and to be able to respond to a collection of information; to search data sources; to complete and review the collection of information; and to transmit or otherwise disclose the information. The total annual burden hours estimated for this Information Collection Request are summarized in the table below.

Total Estimated Annualized burden hours:

Form name	Number of respondents	Number of responses per respondent	Total responses	Average burden per response (in hours)	Total burden hours
Grantee Report	54	1	54	6	324
Client-level Report	54	1	54	109	5,886
Total	54		54		6,210

HRSA specifically requests comments on (1) the necessity and utility of the proposed information collection for the proper performance of the agency's functions, (2) the accuracy of the estimated burden, (3) ways to enhance the quality, utility, and clarity of the information to be collected, and (4) the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

Dated: June 12, 2014.

Jackie Painter,

Deputy Director, Division of Policy and Information Coordination.

[FR Doc. 2014–14193 Filed 6–17–14; 8:45 am]

BILLING CODE 4165–15–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Health Resources and Services Administration

Agency Information Collection Activities: Proposed Collection: Public Comment Request

AGENCY: Health Resources and Services Administration, HHS.

ACTION: Notice.

SUMMARY: In compliance with the requirement for opportunity for public comment on proposed data collection projects (Section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995), the Health Resources and Services Administration (HRSA) announces plans to submit an Information Collection Request (ICR), described below, to the Office of Management and Budget (OMB). Prior to submitting the ICR to OMB, HRSA seeks comments from the public regarding the burden estimate, below, or any other aspect of the ICR.

DATES: Comments on this Information Collection Request must be received no later than August 18, 2014.

ADDRESSES: Submit your comments to *paperwork@hrsa.gov* or mail the HRSA Information Collection Clearance Officer, Room 10–29, Parklawn Building, 5600 Fishers Lane, Rockville, MD 20857.

FOR FURTHER INFORMATION CONTACT: To request more information on the proposed project or to obtain a copy of the data collection plans and draft instruments, email *paperwork@hrsa.gov* or call the HRSA Information Collection Clearance Officer at (301) 443–1984.

SUPPLEMENTARY INFORMATION: When submitting comments or requesting information, please include the information request collection title for reference.

Information Collection Request Title: Federal Tort Claims Act Free Clinic Application OMB No. 0915–0293—Revision

Abstract: Under 42 U.S.C. 233(o) and HRSA Program Assistance Letter (PAL) 2014–04, ''Calendar Year 2015 Federal Tort Claims Act (FTCA) Deeming Application for Free Clinics,'' free clinics are required to submit annual, renewal, and supplemental applications for the process of deeming qualified health care professionals, board members, officers, and contractors for FTCA medical malpractice coverage for negligent acts and omissions that arise from the performance of medical, surgical, dental, or related functions within the scope of the covered individual's employment. HRSA proposes modifying the application forms to reflect changes to eligible personnel made by section 10608 of the Affordable Care Act, amending 42 U.S.C. 233(o)(1), which extended FTCA medical malpractice liability protection to free clinic board members, officers, employees, and contractors. Additionally, HRSA proposes upgrading the application to provide for electronic submissions. Specifically, the modifications include: (1) Inclusion of

board members, officers, employees, and contractors into one comprehensive application that also includes volunteer health care professionals, and (2) a fully electronic application that can be submitted via HRSA's web based application system, the Electronic Handbooks (EHBs). It is anticipated that these modifications will decrease the time and effort required to complete the current OMB approved FTCA application forms.

Need and Proposed Use of the Information: Deemed status for FTCA medical malpractice coverage requires HRSA approval of an application for deeming of certain eligible individuals from a sponsoring free clinic. The FTCA Free Clinic deeming application is an electronic application submitted to HRSA through the EHBs as part of the process of deeming qualified health care professionals, board members, officers, and individual contractors. Sponsoring clinics are required to submit a completed electronic application in addition to other required documents as required by section 224(o) of the Public Health Service Act (42 U.S.C. 233(o)). Applications are reviewed by program staff before a deeming determination is made.

Likely Respondents: Respondents include nonprofit private entities that meet the statutory and programmatic requirements as stated in section 224(o) of the Public Health Service Act (42 U.S.C. 233(o)).

Burden Statement: Burden in this context means the time expended by persons to generate, maintain, retain, disclose or provide the information requested. This includes the time needed to review instructions; to develop, acquire, install and utilize technology and systems for the purpose of collecting, validating and verifying information, processing and maintaining information, and disclosing and providing information; to train personnel and to be able to respond to a collection of information; to search data sources; to complete and review the collection of information; and to transmit or otherwise disclose the information. The total annual burden hours estimated for this Information Collection Request are summarized in the table below.

Total Estimated Annualized burden hours:

Form name	Number of respondents	Number of responses per respondent	Total responses	Average burden per response (in hours)	Total burden hours
FTCA Free Clinics Program Application	227	1	227	2	681
Total	227	1	227	2	681

HRSA specifically requests comments on (1) the necessity and utility of the proposed information collection for the proper performance of the agency's functions, (2) the accuracy of the estimated burden, (3) ways to enhance the quality, utility, and clarity of the information to be collected, and (4) the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

Dated: June 11, 2014.

Jackie Painter,

Deputy Director, Division of Policy and Information Coordination.

[FR Doc. 2014–14192 Filed 6–17–14; 8:45 am]

BILLING CODE 4165–15–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Proposed Collection; 60-Day Comment Request; Cancer Epidemiology Descriptive Cohort Database (NCI)

SUMMARY: In compliance with the requirement of Section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995, for opportunity for public comment on proposed data collection projects, the National Cancer Institute (NCI), National Institutes of Health (NIH), will publish periodic summaries of proposed projects to be submitted to the Office of Management and Budget (OMB) for review and approval.

Written comments and/or suggestions from the public and affected agencies are invited on one or more of the following points: (1) Whether the proposed collection of information is necessary for the proper performance of the function 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, including the validity of the methodology and assumptions used; (3) Ways to enhance the quality, utility, and clarity of the information to be collected; and (4) Ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

To Submit Comments and for Further Information: To obtain a copy of the data collection plans and instruments, submit comments in writing, or request more information on the proposed project, contact: Seminara, Daniela, Senior Scientist and Cohort and Consortia Coordination Team Lead, Epidemiology and Genomics Research Program, Division of Cancer Control and Population Sciences, 9609 Medical Center Drive, Rockville, MD 20892 or call non-toll-free number 240–276–6748 or Email your request, including your address to: *seminard@mail.nih.gov.* Formal requests for additional plans and instruments must be requested in writing.

DATES: *Comment Due Date:* Comments regarding this information collection are best assured of having their full effect if received within 60 days of the date of this publication.

Proposed Collection: Cancer Epidemiology Descriptive Cohort Database, 0925—New, National Cancer Institute (NCI), National Institutes of Health (NIH).

Need and Use of Information Collection: The NCI Epidemiology and Genomics Research Program (EGRP) support large-scale collaborations across numerous cancer epidemiology cohorts. The collaborative approach to date has been lacking in easily accessible, centralized, and searchable information. To address the need for better collaborative research and increased transparency, EGRP will develop a Cancer Epidemiology Descriptive Cohort Database (CEDCD) accessible through a public Web site. The information collected from the current survey will be used to populate the CEDCD. This public Web site will allow investigators to know what data and specimens exist among other cohorts. Respondents will be cohort Principal Investigators (PIs). The data collection forms will be sent to participating

cohort PIs for initial completion and then annually to update any information that has changed so that the CEDCD Web site will remain current. No cohort participant-level data is being collected from any of the cohorts.

The information to be collected will be aggregate descriptive information and protocols. Though the CEDCD has a biospecimen component (similar to the Specimen Resource Locator), the CEDCD is not a biospecimen locator database. It is a database focusing exclusively on descriptive data pertaining to large, prospective epidemiology cohorts.

OMB approval is requested for 3 years. There are no costs to respondents other than their time. The total estimated annualized burden hours are 425.

ESTIMATED ANNUALIZED BURDEN HOURS

Type of respondent	Form name	Number of respondents	Number of responses per respondent	Average burden per response (in hours)	Total annual burden hour
Individual:					
Principal Investigator	Written Agreement Form	100	1	15/60	25
	Biospecimen Spreadsheet	100	1	1	100
Initial Submission	Descriptive Db Collection Form	100	1	1	100
Individual:					
Principal Investigator	Biospecimen Spreadsheet*	200	1	30/60	100
Annual Update	Descriptive Db Collection Form*	200	1	30/60	100

* All forms will be prepopulated with the information that was entered initially.

Dated: June 12, 2014.

Karla Bailey,

NCI Project Clearance Liaison, National Institutes of Health.

[FR Doc. 2014–14275 Filed 6–17–14; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Proposed Collection; 30-Day Comment Request—the Hispanic Community Health Study/Study of Latinos (HCHS/SOL)

SUMMARY: Under the provisions of Section 3507(a)(1)(D) of the Paperwork Reduction Act of 1995, the National Institutes of Health (NIH) has submitted to the Office of Management and Budget (OMB) a request for review and approval of the information collection listed below. This proposed information collection was previously published in the **Federal Register** on March 25, 2014 (Vol. 79, No. 57, pages 16345–16347). 3 comments were received. The purpose of this notice is to allow an additional 30 days for public comment. The National Heart, Lung and Blood Institute (NHLBI), National Institutes of Health, may not conduct or sponsor, and the respondent is not required to respond to, an information collection that has been extended, revised, or implemented on or after October 1, 1995, unless it displays a currently valid OMB control number.

Direct Comments to OMB: Written comments and/or suggestions regarding the item(s) contained in this notice, especially regarding the estimated public burden and associated response time, should be directed to the: Office of Management and Budget, Office of Regulatory Affairs, *OIRA_submission@omb.eop.gov* or by fax to 202–395–6974, Attention: NIH Desk Officer.

DATES: *Comment Due Date:* Comments regarding this information collection are best assured of having their full effect if received within 30-days of the date of this publication.

FOR FURTHER INFORMATION CONTACT: To obtain a copy of the data collection plans and instruments or request more information on the proposed project contact either: Dr. Larissa Aviles-Santa, 6701 Rockledge, Epidemiology Branch, Program in Prevention and Population Sciences, Division of Cardiovascular Sciences, National Heart, Lung, and Blood Institute, National Institutes of Health, 6701 Rockledge Dr., MSC 7936, Bethesda, MD 20892–7936, or call non-toll-free number 301–435–0450, or Email your request, including your address to *avilessantal@nhlbi.nih.gov*. Formal requests for additional plans and instruments must be requested in writing.

Proposed Collection: The Hispanic Community Health Study/Study of Latinos (HCHS/SOL), Revision, National Heart, Lung and Blood Institute (NHLBI), National Institutes of Health (NIH).

Need and Use of Information Collection: The purpose and use of the information collection for this project is to study the prevalence of cardiovascular and pulmonary disease and other chronic diseases, and their risk and protective factors, understand their relationship to all-cause, cardiovascular and pulmonary morbidity and mortality, and understand the role of sociocultural factors (including acculturation) on the prevalence or onset of disease among over 16,400 Hispanics/Latinos of diverse origins, aged 18–74 years at enrollment, living in four U.S. communities: San Diego, California; Chicago, Illinois; Miami, Florida, and the Bronx, New York. In order to achieve these objectives, the HCHS/SOL had two integrated components:

1. Examination of the cohort following a standardized protocol, which consisted of interviews and clinical measurements to assess physiological and biochemical measurements including DNA/RNA extraction for ancillary genetic research studies.

2. Follow-up of the cohort, which consists of an annual telephone interview to assess vital status, changes in health status and medication intake, and new cardiovascular and pulmonary events (including fatal and non-fatal myocardial infarction and heart failure; fatal and non-fatal stroke; and exacerbation of asthma and chronic obstructive pulmonary disease).

OMB approval is requested for 3 years. There are no costs to respondents other than their time. The total estimated annualized burden hours are 30,940.

ESTIMATED ANNUALIZED BURDEN HOURS
A.12.1 ESTIMATES OF HOUR BURDEN
[Appendices 11, 14 and 15]

Type of respondents	Survey instrument	Number of respondents	Number of responses per respondent	Average time per response (in hours)	Total burden hours
Participants Visit 2 Examination (Appendices 11 and 14).	Pre-visit scheduling & safety screening.	13878	1	2/60	463
	Reception, informed consent (Appendix 11), medical releases.	13878	1	20/60	4626
	Ppt. disability screening	13878	1	4/60	925
	Ppt. safety update and routing	13878	1	2/60	463
	Change clothes, urine specimen	13878	1	10/60	2313
	Updated personal information	13878	1	5/60	1157
	Anthropometry	13878	1	7/60	1619
	Determination of fasting & blood draw.	13878	1	11/60	2544
	Determination of blood glucose, OGTT.	13878	1	6/60	1388
	Seated BP	13878	1	9/60	2082
	Echocardiography	8000	1	30/60	4000
	2-hour blood draw, snack	13878	1	12/60	2776
	Personal Medical History	13878	1	10/60	2313
	Reproductive Medical History	9000	1	9/60	1350
	Pregnancy Complications History	9000	1	6/60	900
	Socio-economic Status—Occupation.	13878	1	3/60	694
	Health Care Access and Utilization	13878	1	15/60	3470
	Chronic Stress	13878	1	4/60	925
	Family Cohesion	13878	1	5/60	1157
	Social Support	13878	1	3/60	694
	Acculturation	13878	1	3/60	694
	Well Being	13878	1	4/60	463
	Abbreviated Medication Use	13878	1	4/60	925
	Tobacco Use	13878	1	7/60	1619
	Alcohol Use	13878	1	3/60	694
	Participant Feedback	13878	1	12/60	2776
Total				206/60	43030
Participants AFU Phone Interview (Appendix 15).	AFU Year 3	3146	1	15/60	787
	AFU Year 4	9033	1	15/60	2258
	AFU Year 5	14259	1	15/60	3565
	AFU Year 6	16222	1	15/60	4055
	AFU Year 7	16222	1	15/60	4055
	AFU Year 8	16222	1	15/60	4055
	AFU Year 9	16222	1	15/60	4055
	AFU Year 10	16222	1	15/60	4055
	AFU Year 11	16222	1	15/60	4055
Total				120/60	30940

Dated: June 5, 2014.

Michael Lauer,

Director, DCVS, NHLBI, NIH.

Dated: June 5, 2014.

Lynn Susulske,

NHLBI Project Clearance Liaison, National Institutes of Health.

[FR Doc. 2014–14258 Filed 6–17–14; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HOMELAND SECURITY

United States Immigration and Customs Enforcement

Agency Information Collection Activities: Comment Request; Extension of an Information Collection

ACTION: 30-Day Notice of Information Collection for review; Student and Exchange Visitor Information System (SEVIS); OMB Control No. 1653–0038.

The Department of Homeland Security, U.S. Immigration and Customs Enforcement (USICE), is submitting the following information collection request for review and clearance in accordance with the Paperwork Reduction Act of 1995. The information collection is published in the **Federal Register** to obtain comments from the public and affected agencies. The information collection was previously published in the **Federal Register** on March 28, 2014, Vol. 79 No. 06903 allowing for a 60 day comment period. The purpose of this notice is to allow an additional 30 days for public comments.

Written comments and suggestions regarding items contained in this notice and especially with regard to the estimated public burden and associated

response time should be directed to the Office of Information and Regulatory Affairs, Office of Management and Budget. Comments should be addressed to the OMB Desk Officer for U.S. Immigration and Customs Enforcement, Department of Homeland Security, and sent via electronic mail to *oira_submission@omb.eop.gov* or faxed to (202) 395–5806.

Written comments and suggestions from the public and affected agencies concerning the proposed collection of information should address one or more of the following four points:

(1) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;

(2) Evaluate the accuracy of the agencies estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(3) Enhance the quality, utility, and clarity of the information to be collected; and

(4) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submission of responses.

Overview of This Information Collection

(1) *Type of Information Collection:* Extension of a currently approved information collection.

(2) *Title of the Form/Collection:* Student and Exchange Visitor Information System (SEVIS).

(3) *Agency form number, if any, and the applicable component of the Department of Homeland Security sponsoring the collection:* Forms I–17 and I–20; U.S. Immigration and Customs Enforcement.

(4) *Affected public who will be asked or required to respond, as well as a brief abstract:* Primary: Approximately 37,213 designated school officials (DSOs) representing some 10,715 academic and vocational institutions.

(5) *An estimate of the total number of respondents and the amount of time estimated for an average respondent to respond:*

Number of respondents	Form name/form No.	Average burden per response (in hours)
37,213 DSOs	Form I–17, ''Petition for Approval of School for Attendance by Nonimmigrant Student''	4.000
	Response Action: Initial School Processing.	
	Response Action: Petition Updates	0.249
	Response Action: Recertification Process	4.000
	Response Action: DSO Training, Research, Reports and Professional Development.	14.000
	Form I–17 Hours	22.249
37,213 DSOs	Form I–20, ''Certificate of Eligibility for Nonimmigrant (F–1) Student Status—For Academic and Language Students'' and Form I–20, ''Certificate of Eligibility for Nonimmigrant (M–1) Student Status—For Vocational Students.'' Response Action: F–1/M–1 visa Initial Student Processing (Real Time Interface (RTI)).	1.250
	Response Action: F–1/M–1 visa Initial Student Processing (Batch)	0.040
	Response Action: F–1/M–1 visa Student Updates (RTI)	0.249
	Response Action: F–1/M–1 visa Student Updates (Batch)	0.048
	Response Action: F–1/M–1 visa Student Optional Practical Training (OPT)	0.083
	Response Action: F–1/M–1 visa OPT 17-Month Extension	0.083
	Response Action: F–2/M–2 visa (dependent) Initial Processing (RTI)	0.083
	Response Action: F–2/M–2 visa (dependent) Initial Processing (Batch)	0.016
	Forms I–20 Average Hours	1.852

(6) *An estimate of the total public burden (in hours) associated with the collection:* The burden figures have been updated since the publication of the 60 day **Federal Register** notice to provide better estimates. Form I–17 annual burden hours 537,708; Forms I–20 annual burden hours 490,176. Total annual burden hours 1,027,884.

Dated: June 13, 2014.

Scott Elmore,

Program Manager, Forms Management Office, Office of the Chief Information Officer, U.S. Immigration and Customs Enforcement, Department of Homeland Security.

[FR Doc. 2014–14226 Filed 6–17–14; 8:45 am]

BILLING CODE 9111–28–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5596–N–02]

Section 8 Housing Choice Vouchers: Revised Implementation of the HUD–VA Supportive Housing Program Technical Correction

AGENCY: Office of the Assistant Secretary for Public and Indian Housing, HUD.

ACTION: Notice.

SUMMARY: On March 23, 2012, HUD published a notice, effective as of March 23, 2012, that established the policies and procedures for the administration of tenant-based Section 8 Housing Choice Voucher (HCV) rental assistance under the HUD-Veterans Affairs Supportive Housing (HUD–VASH) program. The March 23, 2012, notice was an update of a HUD–VASH program notice first published by HUD on May 6, 2008. It was recently brought to HUD's intention that one of the HUD regulations that requires waiver in order to allow HUD–VASH families to live on the grounds of a VA facility in units developed to house homeless veterans was not referenced in either the May 6, 2008, notice or the March 23, 2012, notice. Although HUD has waived the requirement since the issuance of the May 6, 2008, notice, the regulatory requirement was inadvertently omitted from the notice. This notice corrects that omission.

DATES: *Effective date:* May 6, 2008.

FOR FURTHER INFORMATION CONTACT: Michael S. Dennis, Director, Office of Housing Voucher Programs, Office of Public Housing and Vouchers Programs,

Office of Public and Indian Housing, Department of Housing and Urban Development, 451 7th Street SW., Room 4216, Washington, DC 20410–8000, telephone number 202–708–0477 (this is not a toll-free number). Individuals with speech or hearing impairments may access this number through TTY by calling the toll-free Federal Relay Service at 800–877–8339.

SUPPLEMENTARY INFORMATION:

I. Background

The HUD–VASH program was authorized pursuant to Division K, Title II, of the Consolidated Appropriations Act, 2008 (Public Law 110–161, approved December 26, 2007) under the heading ''Tenant-Based Rental Assistance'' (FY 2008 Appropriations). The HUD–VASH program combines HCV rental assistance for homeless veterans with case management and clinical services provided by the VA through its community medical centers. The program is administered by PHAs that partner with local VA medical facilities. Since implementation of the program, ongoing VA case management, health, and other supportive services have been made available to homeless veterans at more than 300 VA Medical Center (VAMC) supportive services sites and Community-Based Outpatient Clinics (CBOCs) across the nation. The HUD–VASH program is a key component of reducing homelessness among veterans as outlined in the Administration's Federal Strategy to Prevent and End Homelessness.

Following enactment of the FY 2008 Appropriations, HUD published a notice on May 6, 2008, at 73 FR 25026, which established the policies and procedures for the administration of tenant-based Section 8 HCV rental assistance under the HUD–VASH program. The appropriations acts following the FY 2008 Appropriations Act continued to fund the HUD–VASH program.

By notice published on March 23, 2012, at 77 FR 17086, HUD updated the policies and procedures for the administration of the HUD–VASH program, republishing these policies and procedures in their entirety. In addition to updating the 2008 policies and procedures, the March 23, 2012, notice was also issued to provide new and clarifying guidance regarding several aspects of the program such as those pertaining to certain types of verification documentation, addition of family members after the veteran is a participant in the HCV program, termination of assistance, portability moves within the same catchment area where both PHAs have received HUD–VASH vouchers, portability moves when case management is no longer required, reallocation of HUD–VASH vouchers, and Housing Quality Standards (HQS) initial inspections.

It was recently brought to HUD's attention that one of the HUD regulations that requires waiver in order to allow HUD–VASH families to live on the grounds of a VA facility in units developed to house homeless veterans was not referenced in either the May 6, 2008, notice or the March 23, 2012, notice. Section II.e. of the May 6, 2008, notice, and Section II.f. of the March 23, 2012, notice, which each address ineligible housing, reference waiver of HUDs regulation at 24 CFR 982.352(a)(5) (which covers section 8 housing choice voucher tenant-based assistance) but inadvertently omitted reference to a corresponding provision covering section 8 project-based voucher assistance, specifically, 24 CFR 983.53(a)(2). The latter provision also must be waived to fulfill HUD's intent of allowing VASH families (whether receiving tenant-based or project-based assistance) to live on the grounds of a VA facility. Although § 983.53(a)(2) was inadvertently omitted in each of these notices, the waiver of § 983.53(a)(2) has been applied by HUD as if the regulatory section had been included in the initial May 6, 2008, notice.

This notice published today corrects the paragraph on ineligible housing in the March 23, 2012, notice to include reference to 24 CFR 983.53(a)(2). Since the March 23, 2012, notice was an update of the May 6, 2008, notice there is no need to make the technical correction to the May 6, 2008, notice.

II. Technical Correction

HUD's notice published on March 23, 2012, at 77 FR 17086, specifically subsection II.f. entitled ''Ineligible Housing,'' and found at 77 FR 17089 (middle column) is corrected to read as follows:

f. Ineligible Housing

HUD–VASH families will be permitted to live on the grounds of a VA facility in units developed to house homeless veterans. Therefore, 24 CFR 982.352(a)(5) and 983.53(a)(2), which prohibit units on the physical grounds of a medical, mental, or similar public or private institution, are waived for that purpose only.

Date: June 12, 2014.

Sandra B. Henriquez,

Assistant Secretary for Public and Indian Housing.

[FR Doc. 2014–14167 Filed 6–17–14; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–NERO–STSP–15908; PPNESTSP00 PPMPSPD1Z.YM0000]

Notice of Meeting for Star-Spangled Banner National Historic Trail Advisory Council

AGENCY: National Park Service, Interior.

ACTION: Notice of Meeting.

SUMMARY: As required by the Federal Advisory Committee Act (5 U.S.C. Appendix 1–16), the National Park Service (NPS) is hereby giving notice that the Advisory Council for the Star-Spangled Banner National Historic Trail will hold a meeting. The trail commemorates the Chesapeake Campaign of the War of 1812, including the British invasion of Washington, District of Columbia, and its associated feints, and the Battle of Baltimore in summer 1814.

This meeting is open to the public. Preregistration is required for both public attendance and comment. Any individual who wishes to attend the meeting and/or participate in the public comment session should register via email at *Christine_Lucero@nps.gov* or telephone (757) 258–8914. For those wishing to make comments, please provide a written summary of your comments prior to the meeting. The Designated Federal Official for the Advisory Council is Suzanne Copping, Program Manager, telephone (410) 260–2476.

DATES: The Star-Spangled Banner National Historic Trail Advisory Council will meet from 10:00 a.m. to 3:00 p.m. on Wednesday, July 9, 2014 (eastern).

ADDRESSES: The meeting will be held at the Maryland Archaeological Conservation Lab at Jefferson Patterson Park & Museum, 10515 Mackall Road, St. Leonard, MD 20685.

FOR FURTHER INFORMATION CONTACT: Christine Lucero, Partnership Coordinator, Chesapeake Bay Office, telephone (757) 258–8914 or email *Christine_Lucero@nps.gov.*

SUPPLEMENTARY INFORMATION: Under section 10(a)(2) of the Federal Advisory Committee Act (5 U.S.C. Appendix 1–16), this notice announces a meeting of the Star-Spangled Banner National Historic Trail Advisory Council. Topics to be discussed include setting priorities for the trail in the coming years and the potential creation of a ''Friends Group.''

The Council meeting is open to the public. Comments will be taken for 30 minutes at the end of the meeting (from

2:30 p.m. to 3:00 p.m.). Before including your address, telephone number, email address, or other personal indentifying 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 may ask us in your comment to withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so. All comments will be made part of the public record and will be electronically distributed to all Council members.

Dated: June 12, 2014.

Alma Ripps,

Chief, Office of Policy.

[FR Doc. 2014–14234 Filed 6–17–14; 8:45 am]

BILLING CODE 4310–EE–P

DEPARTMENT OF THE INTERIOR

Bureau of Ocean Energy Management

[Docket No. BOEM–2014–0034; MMAA104000]

Atlantic Wind Lease Sale 4 (ATLW4) Commercial Leasing for Wind Power on the Outer Continental Shelf Offshore Massachusetts—Proposed Sale Notice

AGENCY: Bureau of Ocean Energy Management (BOEM), Interior.

ACTION: Proposed Sale Notice for Commercial Leasing for Wind Power on the Outer Continental Shelf Offshore Massachusetts.

SUMMARY: This document is the Proposed Sale Notice (PSN) for the sale of commercial wind energy leases on the Outer Continental Shelf (OCS) offshore Massachusetts, pursuant to BOEM's regulations at 30 CFR 585.216. BOEM proposes to offer for sale four leases: Lease OCS–A 0500, Lease OCS–A 0501, Lease OCS–A 0502, and Lease OCS–A 0503. BOEM proposes to use a multiple-factor auction format for the lease sale. In this PSN, you will find information pertaining to the areas available for leasing, proposed lease provisions and conditions, auction details, the lease form, criteria for evaluating competing bids, award procedures, appeal procedures, and lease execution. BOEM invites comments during a 60-day comment period following publication of this notice. The issuance of the leases that would result from this proposed sale would not constitute approval of project-specific plans to develop offshore wind energy. Such plans, expected to be submitted by successful lessees, will be subject to subsequent environmental and public review prior to a decision to proceed with development.

DATES: Comments should be submitted electronically or postmarked no later than August 18, 2014. All comments received or postmarked during the comment period will be made available to the public and considered prior to publication of the Final Sale Notice (FSN).

All bidders interested in participating in the lease sale who have not previously been qualified by BOEM to participate in this lease sale must submit the required qualification materials by the end of the 60-day comment period for this notice. All qualification materials must be postmarked no later than August 18, 2014.

ADDRESSES: Potential auction participants, Federal, state, and local government agencies, tribal governments, and other interested parties are requested to submit their written comments on the PSN in one of the following ways:

1. *Electronically: http://www.regulations.gov*. In the entry entitled, ''Enter Keyword or ID,'' enter BOEM–2014–0034 then click ''search.'' Follow the instructions to submit public comments.

2. *Written Comments:* In written form, delivered by hand or by mail, enclosed in an envelope labeled ''Comments on Massachusetts PSN'' to: Office of Renewable Energy Programs, Bureau of Ocean Energy Management, 381 Elden Street, HM 1328, Herndon, Virginia 20170.

3. *Qualifications Materials:* Those submitting qualifications materials should contact Jessica Stromberg, BOEM Office of Renewable Energy Programs, 381 Elden Street, HM 1328, Herndon, Virginia 20170, (703) 787–1320, or *jessica.stromberg@boem.gov*.

If you wish to protect the confidentiality of your comments or qualification materials, clearly mark the relevant sections and request that BOEM treat them as confidential. Please label privileged or confidential information with the caption ''Contains Confidential Information'' and consider submitting such information as a separate attachment. Treatment of confidential information is addressed in the section of this PSN entitled ''Protection of Privileged or Confidential Information.'' Information that is not labeled as privileged or confidential will be regarded by BOEM as suitable for public release.

FOR FURTHER INFORMATION CONTACT: Jessica Stromberg, BOEM Office of Renewable Energy Programs, 381 Elden Street, HM 1328, Herndon, Virginia 20170, (703) 787–1320 or *jessica.stromberg@boem.gov*.

Authority: This PSN is published pursuant to subsection 8(p) of the OCS Lands Act (43 U.S.C. 1337(p)) (the Act), as amended by section 388 of the Energy Policy Act of 2005 (EPAct), and the implementing regulations at 30 CFR Part 585, including 30 CFR 585.211 and 30 CFR 585.216.

Background: The area described for leasing in this PSN is the same as the Wind Energy Area (WEA) that BOEM announced on May 30, 2012, (see Area Identification announcement available at: *http://www.boem.gov/Renewable-Energy-Program/State-Activities/Massachusetts.aspx*). Detailed information regarding the lease areas is provided in the section entitled, ''Areas Offered for Leasing.''

On November 2, 2012, BOEM published a Notice of Availability (NOA) for the *Commercial Wind Lease Issuance and Site Assessment Activities on the Atlantic Outer Continental Shelf (OCS) Offshore Massachusetts* Environmental Assessment (EA) (77 FR 66185) with a 30-day public comment period. BOEM received 25 comments, which are available at: *http://www.boem.gov/Renewable-Energy-Program/State-Activities/MA/Commercial-Wind-Leasing-Offshore-Massachusetts.aspx*. BOEM has concluded consultations under the Endangered Species Act (ESA) and Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA). BOEM will initiate consultations under the Coastal Zone Management Act (CZMA) concurrent with the publication of a revised EA. BOEM has prepared and executed a programmatic agreement (PA) to guide its consultations under Section 106 of the National Historic Preservation Act (NHPA). The PA provides for consultations to continue through BOEM's decision-making process regarding the approval, approval with modification, or disapproval of a lessee's Site Assessment Plan (SAP), and allows for phased identification and evaluation of historic properties.

Based on the public comments received in response to the EA, the conclusion of required consultations, and public outreach and information meetings, BOEM decided to make certain revisions to the EA originally published in November 2012. As a result of the analysis in the revised EA, BOEM is issuing a Finding of No Significant Impact (FONSI). The *Commercial Wind Lease Issuance and*

Site Assessment Activities on the Atlantic Outer Continental Shelf (OCS) Offshore Massachusetts Revised Environmental Assessment (EA) and the FONSI can be found at: *http://www.boem.gov/Renewable-Energy-Program/State-Activities/MA/Commercial-Wind-Leasing-Offshore-Massachusetts.aspx.*

Additional environmental reviews will be conducted upon receipt of a successful Lessee's proposed project-specific plans, such as a SAP or Construction and Operations Plan (COP).

Deadlines and Milestones for Bidders: This section describes the major deadlines and milestones in the auction process from publication of this PSN to execution of leases pursuant to the sale. These are organized into various stages: (1) The PSN comment period; (2) from the end of PSN comment period to publication of the FSN; (3) the FSN waiting period; (4) conducting the Auction; and (5) from the Auction Stage to Lease Execution.

1. The PSN Comment Period

- *Submit Comments:* The public is invited to submit comments during this 60-day period.
- *Public Seminar:* BOEM will host a public seminar to discuss the lease sale process and the auction format.
- *Receive Qualifications Materials:* All qualifications materials must be received by BOEM by the end of the 60-day PSN comment period. This includes materials sufficient to establish a company's legal, technical and financial qualifications.

2. End of PSN Comment Period to FSN Publication

- *Review Comments:* BOEM will review all comments submitted in response to the PSN during the comment period.
- *Finalize Qualifications Reviews:* BOEM will complete any outstanding qualifications reviews using materials that were submitted during the PSN comment period and requested by BOEM prior to the publication of the FSN. The final list of eligible bidders will be published in the FSN.
- *Prepare the FSN:* BOEM will prepare the FSN by updating the PSN where appropriate.
- *Select and Invite Panelists:* BOEM will appoint a panel of three BOEM employees for the purposes of reviewing the non-monetary packages and verifying the results of the lease sale.
- *Publish FSN:* BOEM will publish the FSN in the **Federal Register**.

3. FSN Waiting Period

- *Bidder's Financial Form (BFF):* No later than 14 days after publication of the FSN in the **Federal Register**, eligible bidders must submit a complete and signed BFF to BOEM. Once this information has been processed by BOEM, bidders may log into *pay.gov* and leave bid deposits. If BOEM does not receive the BFF by the date mentioned in the **Federal Register**, a company may be disqualified from participating in the auction.
- *Bid Deposits:* No later than 30 days after publication of the FSN in the **Federal Register**, bidders must submit a bid deposit meeting the requirements listed in the FSN. Any bidder that fails to submit the bid deposit by the deadline included in the FSN may be disqualified from participating in the auction.
- *Non-Monetary Package:* No later than 30 days after publication of the FSN in the **Federal Register,** bidders seeking a non-monetary credit must submit a non-monetary package meeting the requirements listed in the FSN.
- *Mock Auction:* BOEM will hold a Mock Auction, open to qualified sale bidders only. The Mock Auction will take place approximately one week before the lease sale. Final details of the Mock Auction will be provided in the FSN.

4. Conducting the Auction

BOEM, through its contractor, will hold an auction as described in this notice. The auction will take place no sooner than 30 days following publication of the FSN in the **Federal Register**. The estimated timeframes described in this notice assume an auction date approximately 45 days after publication of the FSN.

- *Convene Panel:* The panel will convene to consider non-monetary packages submitted by qualified bidders. The panel will send determinations of credit eligibility to BOEM, and BOEM will inform eligible bidders. Bidders will not be informed of the non-monetary credit eligibility of other bidders before the auction.
- *Monetary Auction:* The monetary auction will be conducted on the date specified in the FSN.
- *Announce Provisional Winners:* BOEM will announce the provisional winners of the lease sale after the auction ends.
- *Reconvene the Panel:* The panel will reconvene to verify auction results.

5. From Auction to Lease Execution

- *Refund Non-Winners:* BOEM will return the bid deposit of any bidder that did not win a lease in the lease sale. BOEM will provide a written explanation of why the bidder did not win.
- *Department of Justice (DOJ) Review:* BOEM will allow DOJ 30 days in which to conduct an antitrust review of the auction, pursuant to 43 U.S.C. 1337(c), which reads, in relevant part:

Antitrust review of lease sales. Following each notice of a proposed lease sale and before the acceptance of bids and the issuance of leases based on such bids, the Secretary of the Department of the Interior shall allow the Attorney General, in consultation with the Federal Trade Commission, 30 days to review the results of such lease sale, except that the Attorney General, after consultation with the Federal Trade Commission, may agree to a shorter review period.

- *Delivery of Leases:* BOEM will send three lease copies to each winner, with instructions on how to execute the leases. The first year's rent payment is due 45 days after the winner receives the lease copies for execution.
- *Return the Leases:* The auction winners will have 10 business days from receiving the lease copies in which to file financial assurance, pay any outstanding balance of their bonus bids, and return the three executed lease copies.
- *Execution of Leases:* Once BOEM has received the signed lease copies and verified that all required materials have been received, BOEM will make a final determination regarding its execution of the leases and will execute the leases if appropriate.

Financial Terms and Conditions: This section provides an overview of the basic annual payments required of a Lessee that will be fully described in each lease, and the financial assurance requirements that will be associated with each lease.

BOEM has proposed these financial terms and conditions in this PSN and in the four commercial leases that accompany the PSN. However, BOEM recognizes that there may be concerns related to the potential costs associated with development of commercial wind energy projects in the water depths associated with the Massachusetts WEA. Therefore, BOEM is requesting comments in order to evaluate whether the following modifications to said terms and conditions are warranted: (1) Reduction of the annual rent to less than $3 per acre; (2) reduction of the annual rent for any project easement associated with the lease; and (3) reduction of the annual operating fee rate to less than 0.02 (i.e., 2%). If a potential bidder is interested in obtaining a lease that

reflects the adjustments to the financial terms and conditions described above, then that party should submit their qualifications package during the comment period of this PSN, in addition to submitting comments and proposed revisions to the financial terms and conditions.

Rent

The first year's rent payment of $3 per acre for the entire Lease Area (LA) is due within 45 days of the date the Lessee receives the lease for execution. Thereafter, annual rent payments are due on the anniversary of the Effective Date of the lease, i.e., the Lease Anniversary. Once the first commercial operations under the lease begin, rent will be charged on the remaining part of the lease not authorized for commercial operations, i.e., not generating electricity. However, instead of geographically dividing the LA into acreage that is ''generating'' and acreage that is ''non-generating,'' the fraction of the lease accruing rent is based on the fraction of the total nameplate capacity of the project that is not yet in operation. The fraction is the nameplate capacity (as defined herein), which is not yet authorized for commercial operations at the time payment is due, divided by the maximum nameplate capacity after full installation of the project, as defined in the COP. This fraction is then multiplied by the amount of rent that would be due for the Lessee's entire LA at the rental rate of $3 per acre, to obtain the annual rent due for a given year.

For example, for a lease the size of 742,978 acres (the size of the entire Massachusetts WEA), the amount of rent payment would be $2,228,934 per year if no portion of the leased area is authorized for commercial operations. If 500 megawatts (MW) of a project's nameplate capacity is operating (or authorized for operation), and its most recent approved COP specifies a maximum nameplate capacity of 1000 MW, the rent payment would be $1,114,467. For the above example, this would be calculated as follows: 500 MW/1000 MW × ($3/acre × 742,978 acres) = $1,114,467.

The Lessee also must pay rent for any project easement associated with the lease commencing on the date that BOEM approves the COP (or COP modification) that describes the project easement. Annual rent for a project easement 200-feet wide and centered on the transmission cable is $70.00 per statute mile. For any additional acreage required, the Lessee must also pay the greater of $5.00 per acre per year or $450.00 per year.

BOEM is requesting comments and supporting information to determine whether it should modify rent payments for the commercial leases to be executed for the Massachusetts WEA.

Operating Fee

For the purposes of calculating the initial annual proposed operating fee payment, an operating fee rate is applied to a proxy for the wholesale market value of the electricity expected to be generated from the project during its first twelve months of operations. This initial payment is prorated to reflect the period between the commencement of commercial operations and the Lease Anniversary. The initial annual operating fee payment is due within 45 days of the commencement of commercial operations. Thereafter, subsequent annual operating fee payments are due on or before each Lease Anniversary. The subsequent annual operating fee payments are calculated by multiplying an operating fee rate by the imputed wholesale market value of the projected annual electric power production. For the purposes of this calculation, the imputed market value is the product of the project's annual nameplate capacity, the total number of hours in the year (8,760), a capacity utilization factor, and the annual average price of electricity derived from a historical regional wholesale power price index. For example, an annual operating fee for a 100 MW wind facility operating at 40% capacity with a regional wholesale power price of $40/MWh under an operating fee rate of 0.02 (i.e., 2%) would be calculated as follows: Annual operating fee = 100 MW × 8,670 hours/year × 0.4 × $40/MWh power price × 0.02.

Operating Fee Rate: BOEM is proposing a fixed operating fee rate of 0.02 (i.e., 2%) during the project's entire life of commercial operations. BOEM is requesting comments and supporting information to determine whether it should modify the proposed operating fee rate for the commercial lease agreements to be executed for the Massachusetts WEA.

Nameplate Capacity: Nameplate capacity is the maximum rated electric output, expressed in MW, which the turbines of the wind facility under commercial operations can produce at their rated wind speed as designated by the turbine's manufacturer. The nameplate capacity at the start of each year of commercial operations on the lease will be specified in the COP. For example, if a Lessee has 20 turbines under commercial operations rated by the design manufacturer at 5 MW of output each, the nameplate capacity of the wind facility at the rated wind speed of the turbines would be 100 MW.

Capacity Factor: The capacity factor relates to the amount of energy delivered to the grid during a period of time compared to the amount of energy the wind facility would have produced at full capacity during that same period of time. This factor is represented as a decimal between zero and one. There are several reasons why the amount of power delivered is less than the theoretical 100% of capacity. For a wind facility, the capacity factor is mostly determined by the availability of wind. Transmission line loss and down time for maintenance or other purposes also affect the capacity factor.

The capacity factor for the year in which the Commercial Operation Date occurs and for the first six full years of commercial operations on the lease is set to 0.4 (i.e., 40%) to allow for one year of installation and testing followed by five years at full availability. At the end of the sixth year, the capacity factor may be adjusted to reflect the performance over the previous five years based upon the actual metered electricity generation at the delivery point to the electrical grid. Similar adjustments to the capacity factor may be made once every five years thereafter. The maximum change in the capacity factor from one period to the next will be limited to plus or minus 10 percent of the previous period's value.

Wholesale Power Price Index: The wholesale power price, expressed in dollars per MW-hour, is determined at the time each annual operating fee payment is due, based on the weighted average of the inflation-adjusted peak and off-peak spot price indices for the Northeast—Massachusetts Hub power market for the most recent year of data available as reported by the Federal Energy Regulatory Commission (FERC) as part of its annual *State of the Markets Report* with specific reference to the summary entitled, ''Electric Market Overview: Regional Spot Prices.'' The wholesale power price is adjusted for inflation from the year associated with the published spot price indices to the year in which the operating fee is to be due based on the Lease Anniversary using annual implicit price deflators as reported by the U.S. Department of Commerce, Bureau of Economic Analysis.

Financial Assurance

Within 10 business days after receiving the lease copies, the provisional winner must provide an initial lease-specific bond or other approved means of meeting the Lessor's

initial financial assurance requirements, in the amount of $100,000. BOEM will base the amount of all SAP, COP, and decommissioning financial assurance requirements on estimates of cost to meet all accrued lease obligations. The amount of supplemental and decommissioning financial assurance requirements will be determined on a case-by-case basis.

The financial terms can be found in Addendum ''B'' of the proposed leases, which BOEM has made available with this notice on its Web site at: *http://www.boem.gov/Renewable-Energy-Program/State-Activities/Massachusetts.aspx.*

Place and Time: The auction will be held online. The time that the auction will be held will be published in the FSN. The date has not been finalized, but will be no earlier than 30 days after publication of the FSN in the **Federal Register.**

Public Seminar: BOEM will host a public seminar to introduce potential bidders and other stakeholders to the auction format provided in the PSN, explain the auction rules, and demonstrate the auction process. The time and place of the seminar will be announced by BOEM and published on the BOEM Web site. No registration or RSVP will be required to attend.

Mock Auction: BOEM will host a Mock Auction to educate qualified bidders about the procedures to be employed during the auction and to answer questions. The Mock Auction will take place between the publication of the FSN in the **Federal Register** and the date of the auction. Following publication of the FSN in the **Federal Register,** details of the Mock Auction will be distributed to those eligible to participate in the auction. All qualified bidders that intend to participate in the auction are strongly encouraged to participate in the Mock Auction. Bidders will be eligible to participate in the Mock Auction if they have been legally, technically and financially qualified to participate in the lease sale, and have submitted an adequate bid deposit as discussed herein.

Bid Deposit: A bid deposit is an advance cash deposit submitted to BOEM in order to participate in the auction. No later than the deadline provided in the FSN, each bidder must have submitted a bid deposit of $450,000 per unit of desired initial eligibility. Each lease is worth one unit of bid eligibility in the auction. Any participant intending to bid on only one of the leases during the auction must submit a bid deposit of $450,000. The required bid deposit for any participant intending to bid on multiple leases in the first round of the auction will be the number of leases the bidder intends to bid on multiplied by $450,000. For example, the required bid deposit for any participant intending to bid on three leases in the first round of the auction will be $1,350,000. Any bidder that fails to submit the bid deposit by the deadline described in the FSN may be disqualified from participating in the auction. Bid deposits will be accepted online via *pay.gov.* Following publication of the FSN, each bidder must fill out the BFF included in the FSN. BOEM has made a copy of the proposed BFF available with this notice on its Web site at: *http://www.boem.gov/Renewable-Energy-Program/State-Activities/Massachusetts.aspx.* This form requests that each bidder designate an email address, which the bidder should use to create an account in *pay.gov.* After establishing the *pay.gov* account, bidders may use the Bid Deposit Form on the *pay.gov* Web site to leave a deposit.

Following the auction, bid deposits will be applied against any bonus bids or other obligations owed to BOEM. If the bid deposit exceeds a bidder's total financial obligation, the balance of the bid deposit will be refunded to the bidder. BOEM will refund bid deposits to unsuccessful bidders.

Minimum Bid: In this auction, approximately 187,523 acres will be offered for sale as Lease OCS–A 0500, approximately 166,886 acres will be offered for sale as Lease OCS–A 0501, approximately 248,015 acres will be offered for sale as Lease OCS–A 0502, and approximately 140,554 acres will be offered for sale as Lease OCS–A 0503. BOEM proposes for this lease sale a minimum bid of $2 per acre for each LA. Therefore, the minimum acceptable bid will be $375,046 for Lease OCS–A 0500, $333,772 for Lease OCS–A 0501, $496,030 for Lease OCS–A 0502, and $281,108 for Lease OCS–A 0503.

Area Offered for Leasing: The area described for leasing in this PSN is the same as the Massachusetts WEA described as the proposed action and preferred alternative in the EA. The area proposed to be available for sale will be auctioned as four leases: Lease OCS–A 0500, Lease OCS–A 0501, Lease OCS–A 0502, and Lease OCS–A 0503. Lease OCS–A 0500 consists of 187,523 acres, Lease OCS–A 0501 consists of 166,886 acres, Lease OCS–A 0502 consists of 248,015 acres, and Lease OCS–A 0503 consists of 140,554 acres. The total area is approximately 742,978 acres. If there are adequate bids, four leases will be issued pursuant to this lease sale. A description of the LAs can be found in Addendum ''A'' of the proposed leases, which BOEM has made available with this notice on its Web site at: *http://www.boem.gov/Renewable-Energy-Program/State-Activities/Massachusetts.aspx.*

Map of the Area Offered for Leasing

A map of the four proposed LAs and a table of the boundary coordinates in X, Y (eastings, northings) UTM Zone 18, NAD83 Datum and geographic X, Y (longitude, latitude), NAD83 Datum can be found at the following URL: *http://www.boem.gov/Renewable-Energy-Program/State-Activities/Massachusetts.aspx.*

A large scale map of these areas showing boundaries of the area with numbered blocks is available from BOEM at the following address: Bureau of Ocean Energy Management, Office of Renewable Energy Programs, 381 Elden Street, HM 1328, Herndon, Virginia 20170, Phone: (703) 787–1320, Fax: (703) 787–1708.

Delineation of the Leasing Areas

BOEM commissioned the Department of Energy's National Renewable Energy Laboratory (NREL) to develop a methodology for delineation of the Massachusetts WEA into non-overlapping LAs for BOEM to consider for inclusion in this PSN. NREL obtained relevant information related to the Massachusetts WEA, such as bathymetry and wind speed information, and calculated gross capacity and annual energy production using different wind turbine generator spacing and layout scenarios. BOEM provided NREL with the industry nominations received in response to previously published notices associated with BOEM's Massachusetts offshore wind planning process to inform this analysis. Additionally, NREL conducted wake effects analysis with the goal of minimizing wake effects between LAs. NREL also provided draft reports and presented the draft and final findings to the BOEM Massachusetts Intergovernmental Renewable Energy Task Force. NREL's final report, entitled ''Assessment of Offshore Wind Energy Leasing Areas for the BOEM Massachusetts Wind Energy Area,'' was released on December 20, 2013, and is available on BOEM's Web site at: *http://www.boem.gov/Renewable-Energy-Program/State-Activities/Massachusetts.aspx.*

In the final report, NREL presented three alternatives for BOEM's consideration for delineation of the Massachusetts WEA: Alternative 1 consists of four LAs divided along diagonal lines parallel to the prevailing wind direction (southwest to northeast)

and perpendicular to the bathymetry; Alternative 2 consists of five LAs divided along diagonal lines parallel to the prevailing wind direction and perpendicular to the bathymetry; and Alternative 3 consists of five LAs, four divided along diagonal lines parallel to the prevailing wind direction and perpendicular to the bathymetry, and the fifth comprised mostly of water depths greater than 50 meters. In the final report, NREL indicated that their preferred delineation option is Alternative 2 because it would maximize the development potential of the Massachusetts WEA. After sharing the results of NREL's analysis with the BOEM Massachusetts Intergovernmental Task Force, BOEM received one comment from the Commonwealth of Massachusetts indicating that their preferred delineation would be Alternative 1 because it would allow individual lessees the maximum flexibility in designing projects.

In this PSN, BOEM is proposing to auction the Massachusetts WEA as four leasing areas as described in Alternative 1 of NREL's final report. However, potential bidders should note that BOEM may choose to offer for sale the LAs outlined in Alternative 2 or 3 of NREL's final report, after considering the comments submitted in response to the PSN. BOEM will announce its final decision as to the Massachusetts WEA leasing areas that will be offered for sale in the FSN.

Withdrawal of Blocks: Interested parties should note that BOEM reserves the right to withdraw portions of the LAs prior to its execution of a lease based upon comments received in response to this PSN and other relevant information provided to the Bureau.

Lease Terms and Conditions: The proposed leases contain proposed lease terms, conditions and stipulations for OCS commercial wind leases in the Massachusetts WEA. BOEM reserves the right to add additional terms and conditions to any approval or approval with modifications of a SAP and/or COP. The proposed leases, including Addendum ''C'', are available on BOEM's Web site at: *http://www.boem.gov/Renewable-Energy-Program/State-Activities/Massachusetts.aspx*. Each proposed lease includes the following seven attachments:

- Addendum ''A'' (Description of Leased Area and Lease Activities);
- Addendum ''B'' (Lease Term and Financial Schedule);
- Addendum ''C'' (Lease Specific Terms, Conditions, and Stipulations);
- Addendum ''D'' (Project Easement);
- Addendum ''E'' (Rent Schedule);
- Appendix A to Addendum ''C'': (Incident Report: Protected Species Injury or Mortality); and
- Appendix B to Addendum ''C'': (Required Data Elements for Protected Species Observer Reports).

Addenda ''A'', ''B'', and ''C'' provide detailed descriptions of lease terms and conditions. Addenda ''D'' and ''E'' will be completed at the time of COP approval.

After considering comments on the PSN and proposed leases, BOEM will publish final lease terms and conditions in the FSN.

Required Plans for Potential Development of Executed Leases

Pursuant to 30 CFR 585.601, the leaseholder must submit a SAP within 12 months of lease issuance. If the leaseholder intends to continue its commercial lease with an operations term, the leaseholder must submit a COP at least 6 months before the end of the site assessment term.

The commercial wind leasing areas proposed for sale in this PSN are among the largest delineated by BOEM to date. In light of this, BOEM is soliciting comments on the concept of executing commercial leases for the Massachusetts WEA with an operations term greater than the 25 years proposed in this PSN. If a potential bidder is interested in obtaining a lease that reflects the adjustments to the operations term described above, then that party should submit their comments and qualifications package during the comment period of this PSN. The decision whether to execute leases with an operations term greater than 25 years will be made in accordance with 30 CFR 585.235.

Qualifications—Who May Bid: Any potential bidder that has not already submitted a complete set of qualifications materials must do so by the end of the 60-day comment period of this PSN. To be eligible to participate in the auction, each potential bidder must have been found by BOEM to be legally, technically and financially qualified under BOEM's regulations at 30 CFR 585.106–107 by the time the FSN for this sale is published. Please note that technical and financial qualifications are lease-specific; it is not sufficient to have been technically and financially qualified to pursue a project offshore another state.

Guidance and examples of the appropriate documentation demonstrating the required legal qualifications can be found in Chapter 2 and Appendix B of *Guidelines for the Minerals Management Service Renewable Energy Framework,* available on BOEM's Web site at: *http://www.boem.gov/Renewable-Energy-Program/Regulatory-Information/Index.aspx*. Guidance regarding how bidders may demonstrate their technical and financial qualifications is provided in *Qualification Guidelines to Acquire and Hold Renewable Energy Leases and Grants and Alternate Use Grants on the U.S. Outer Continental Shelf,* available on BOEM's Web site at: *http://boem.gov/Renewable-Energy-Program/Regulatory-Information/QualificationGuidelines-pdf.aspx*. BOEM strongly recommends that bidders refer to this guidance before submitting their qualification materials, as the guidance is updated periodically.

Bidders must submit documentation necessary to demonstrate their legal, technical, and financial qualifications to BOEM in both paper and electronic formats. BOEM considers an Adobe PDF file stored on a compact disc (CD) to be an acceptable format for submitting an electronic copy. In their qualification materials, bidders must provide a general description of the project that they would like to construct on the LA sought in this sale, including estimates of the project area and total nameplate capacity of the proposed facilities.

Please note that it may take a number of weeks for bidders to establish their legal, technical, and financial qualifications. BOEM advises potential bidders planning to participate in a sale to establish their qualifications promptly. It is not uncommon for BOEM to request additional materials establishing qualifications following an initial review of the qualifications package. Any potential bidder whose qualification package is incomplete at the time the FSN for this sale is published in the **Federal Register** will be found to have failed to establish its qualifications and will be unable to participate in the sale.

Finally, potentially interested parties should note that BOEM may decide to move forward with one of the other two LA alternatives outlined in NREL's final report, based upon comments received in response to this PSN and other relevant information provided to the Bureau. Potentially interested parties should also note that BOEM is considering (1) lowering certain payment requirements, and (2) lengthening the operations terms associated with the proposed commercial leases, as described earlier in this PSN. If a potential bidder is interested in obtaining a lease included in any of the the leasing alternatives outlined in NREL's final report and/or is interested in obtaining a lease with the adjustments to the financial terms and

conditions and/or operations term described in this PSN, then that party should submit their qualifications package during the comment period of this PSN.

Auction Procedures

Summary

For the sale of Lease OCS–A 0500, Lease OCS–A 0501, Lease OCS–A 0502, and Lease OCS–A 0503, BOEM will use a multiple-factor auction format with a multiple-factor bidding system. Under this system, BOEM may consider a combination of monetary and non-monetary factors, or ''variables,'' in determining the outcome of the auction. BOEM will appoint a panel of three BOEM employees for the purposes of reviewing the non-monetary packages and verifying the results of the lease sale. BOEM reserves the right to change the composition of this panel prior to the date of the lease sale. The panel will determine whether any bidder has earned a non-monetary credit to be used during the auction (i.e., if a bidder holds a Community Benefits Agreement (CBA) or a Power Purchase Agreement (PPA)), and if one or more bidders have earned such a credit, the percentage that the credit will be worth. The auction will balance consideration of two variables: (1) A cash bid, and (2) a non-monetary credit. In sum, these two variables comprise the multi-factor bid or ''As-Bid'' auction price. A bidder's As-Bid price, which is the sum of its cash bid and any credit portion earned, will either meet BOEM's asking price or be reflected in the bidder's own Intra-Round Bid price subject to certain conditions, as described more fully herein. A multiple-factor auction, wherein both monetary and nonmonetary bid variables are considered, is provided under BOEM's regulations at 30 CFR 585.220(a)(4) and 585.221(a)(6).

Overview of the Multiple-Factor Bidding Format Proposed for This Sale

Under a multiple-factor bidding format, as set forth at 30 CFR 585.220(a)(4), BOEM may consider a combination of factors as part of a bid. The regulations state that one bid proposal per bidder will be accepted, but do not further specify the procedures to be followed in the multiple-factor format. This multiple-factor format is intended to allow BOEM flexibility in administering the auction and in balancing the variables presented. The regulations leave to BOEM the determination of how to administer the multiple-factor auction format to ensure the receipt of a fair return under the Act, 43 U.S.C. 1337(p)(2)(A).

BOEM's regulations at 30 CFR 585.220(a)(4) allow for a multi-round auction in which each bidder may submit only one proposal per LA or for a set of LAs in each round of the auction. The auction will be conducted in a series of rounds. At the start of each round, BOEM will state an asking price for each LA offered. The asking price for a bid on more than one LA is the sum of the asking prices for each LA in the bid. Each bidder will indicate whether it is willing to meet the asking price for one or more LAs. A bid submitted at the full asking price for one or more LAs in a particular round is referred to as a ''live bid.'' A bidder must submit a live bid for at least one of the LAs in each round to participate in the next round of the auction. As long as there is at least one LA that is included in two or more live bids, the auction continues, and the next round is held.

A bidder's As-Bid price must meet the asking price in order for it to be considered a live bid. A bidder may meet the asking price by submitting a monetary bid equal to the asking price or, if it has earned a credit, by submitting a multiple-factor bid—that is, a live bid that consists of a monetary element and a non-monetary element, the sum of which equals the asking price. A multiple-factor bid would consist of the sum of a cash portion and any credit portion which the bidder has earned.

An uncontested bid is a live bid that does not overlap with other live bids in that round. For example, a bid for two LAs is considered contested if any LA included in that bid is included in another bid—a bid cannot be ''partially uncontested.'' An uncontested bid represents the only apparent interest in that bid's LA(s) at the asking price for that round. If a bidder submits an uncontested bid consisting of one or more LAs, and the auction continues for another round, BOEM automatically carries that same live bid forward as a live bid into the next round, and BOEM's asking price for the LA(s) contained in the uncontested bid would remain unchanged from the previous round. If the price on any LAs in that bid rises later in the auction because another bidder places a live bid on one or more of those LAs, BOEM will stop automatically carrying forward the previously uncontested bid. Once the asking price(s) goes up, the bidder that placed the previously carried-forward bid is free to bid on either LA at the new asking price(s).

Following each round in which a LA is contained in more than one live bid, BOEM will raise the asking price for that LA by an increment determined by BOEM. The auction concludes when each LA is included in no more than one live bid. The series of rounds and the rising asking prices set by BOEM will facilitate consideration of the first variable—the cash portion of the bid.

The second variable—a credit of 5% of a monetary bid for holding a CBA or a credit of up to 25% of a monetary bid for holding a PPA—will be applied throughout the auction rounds as a form of imputed payment against the asking price for the highest priced LA in a bidder's multiple-factor bid. This credit serves to supplement the amount of a cash bid proposal made by a particular bidder in each round. In the case of a bidder holding a credit and bidding on more than one LA, the credit will be applied only on the LA with the highest asking price. More details on the non-monetary factors are found in the ''Credit Factors'' section herein.

The panel will evaluate non-monetary packages consisting of any CBA or PPA to determine whether it meets the criteria provided in the FSN, and therefore whether it will qualify for a credit for its holder. It is possible that the panel could determine that no bidder qualifies for a non-monetary credit during the auction, in which case the auction would otherwise proceed as described in the FSN. The panel will determine the winning bids for each LA on the basis of the procedures described in the FSN.

Details of the Auction Process

Bidding—Live Bids

Each bidder is allowed to submit a live bid for any number of LAs based on its ''eligibility'' at the opening of each round. A bidder's eligibility is either four, three, two, one, or zero LAs, and it corresponds to the maximum number of LAs that a bidder may include in a live bid during a single round of the auction. A bidder's initial eligibility is determined based on the amount of the bid deposit submitted by the bidder prior to the auction. To be eligible to offer a bid on one LA at the start of the auction, a bidder must submit a bid deposit of $450,000. To be eligible to offer a bid on two LAs in the first round of the auction, the bidder must submit a bid deposit of $900,000; for three LAs, the bid deposit is $1,350,000; for four LAs, the bid deposit is $1,800,000. A bidder's bid deposit will be used by BOEM as a down payment on any monetary obligations incurred by the bidder should it be awarded a lease.

As the auction proceeds, a bidder's eligibility is determined by the number

of LAs included in its live bid submitted in the round prior to the current round. That is, if a bidder submitted a live bid on one LA in the previous round, that bidder may submit a bid that includes at most one LA in the current round. If a bidder submitted a live bid comprised of two or more LAs in the previous round, that bidder may submit a live bid that also includes that number of LAs in the current round. Unless a bidder has an uncontested bid that is carried forward into the next round, a bidder that submitted a live bid for one or more LAs also may choose to submit a live bid with fewer LAs than the maximum number it is eligible to include in its bid. Thus, eligibility in successive rounds may stay the same or go down, but it can never go up.

In the first round of the auction, bidders have the following options:

A bidder with an initial eligibility of one (that is, a bidder who submitted a bid deposit of $450,000) may:

- Submit a live bid on any of the four LAs, or
- Submit nothing, and drop out of the auction.

A bidder with an initial eligibility of more than one (that is, a bidder who submitted a bid deposit of $900,000 up to $1,800,000) may:

- Submit a live bid for any number of LAs up to its bid eligibility, or
- Submit nothing, and drop out of the auction.

There is no requirement that the LAs contained in a live bid be contiguous. A bidder who has included multiple LAs in a live bid can include any combination of LAs up to the bidder's bid eligibility. Before each subsequent round of the auction, BOEM will raise the asking price for any LA that was contained in more than one live bid in the previous round. BOEM will not raise the asking price for a LA that was in only one or no live bids in the previous round.

Asking price increments will be determined by BOEM, in its sole discretion. BOEM will base asking price increments on a number of factors, including:

- Making the increments sufficiently large that the auction will not take an unduly long time to conclude; and
- Decreasing the increments as the asking price of a LA nears its apparent final price.

BOEM reserves the right during the auction to increase or decrease increments if it determines, in its sole discretion, that a different increment is warranted to enhance the efficiency of the auction process. Asking prices for the LAs included in multiple live bids in the previous round will be raised and rounded to the nearest whole dollar amount to obtain the asking prices in the current round.

A bidder must submit a live bid in each round of the auction (or have an uncontested live bid automatically carried forward by BOEM) for it to remain active and continue bidding in future rounds. All of the live bids submitted in any round of the auction will be preserved and considered binding until determination of the winning bids is made. Therefore, the bidders are responsible for payment of the bids they submit and can be held accountable for up to the maximum amount of those bids determined to be winning bids during the final award procedures.

Between rounds, BOEM will release the following information to the bidders:

- The level of demand for each LA in the previous round of the auction (i.e., the number of live bids that included the LA); and
- The asking price for each LA in the upcoming round of the auction.

In any subsequent round of the auction, if a bidder's previous round bid was uncontested, and the auction continues for another round, then BOEM will automatically carry forward that bid as a live bid in the next round. A bidder whose bid is being carried forward will not have an opportunity to modify or drop its bid until some other bidder submits a live bid that overlaps with the LA(s) in the carried forward bid. In particular, for rounds in which a bidder finds its uncontested bid is carried forward, the bidder will be unable to do the following:

- Switch to any other LAs;
- Submit an Intra-Round Bid (see herein for discussion of Intra-Round Bids); or
- Drop out of the auction.

A bidder may be bound by that bid or, indeed, by any other bid which BOEM determines is a winning bid in the award stage. Hence, a bidder cannot drop an uncontested bid. In no scenario can a bidder be relieved of any of its bids from previous or future rounds until a determination is made in the award stage about the LAs won by the bidder.

Except when a bidder's bid is being carried forward by BOEM (i.e., an uncontested bid), a bidder with an eligibility of one (that is, a bidder who submitted a live bid for one LA in the previous round) may:

- Submit a live bid for any of the four LAs;
- Submit an Intra-Round Bid for the same LA for which the bidder submitted a live in the previous round, and exit the auction; or
- Submit nothing, and drop out of the auction.

A bidder with an eligibility of two or more (that is, a bidder who submitted a live bid for two or more LAs in the previous round) may:

- Submit a live bid for any number of LAs up to its eligibility;
- Submit an Intra-Round Bid for the specific combination of LAs in that bidder's previous-round bid, and a live bid for any number of LAs fewer than the number of LAs in that bidder's previous-round bid;
- Submit an Intra-Round Bid for the specific combination of LAs in that bidder's previous-round bid, no live bids, and exit the auction; or
- Submit nothing, and drop out of the auction.

Subsequent auction rounds occur in this sale as long as one of the four LAs is contested. The auction concludes at the end of the round in which none of the LAs is included in the live bid of more than one bidder, i.e., all live bids are uncontested.

Bidding—Intra-Round Bids

All asking prices and asking price increments will be determined by the BOEM Auction Manager, as described previously in this PSN. Intra-Round Bidding allows bidders to more precisely express the maximum price they are willing to offer for a single LA or for a combination of LAs while also minimizing the chance of ties. An Intra-Round Bid must consist of a single offer price for exactly the same LA(s) included in the bidder's live bid in the previous round.

When submitting an Intra-Round Bid, the bidder is indicating that it is not willing to meet the current round's asking price, but it is willing to pay more than the previous round's asking price. In particular, in an Intra-Round Bid, the bidder specifies the maximum (higher than the previous round's asking price and less than the current round's asking price) that it is willing to offer for the specific LA(s) in its previous round's live bid.

Although an Intra-Round Bid is not a live bid, in the round in which a valid Intra-Round Bid is submitted for any number of LAs, the bidder's eligibility for a live bid in that same round and future rounds is permanently reduced from including the amount of LAs in the previous round to one less than that. In other words, once an Intra-Round Bid is submitted, the bidder will never again have the opportunity to submit a live bid on as many LAs as it has bid in previous rounds.

BOEM will not consider Intra-Round Bids for the purpose of determining whether to increase the asking price for a particular LA or to end the auction. Also, BOEM will not count nor share with bidders between rounds the number of Intra-Round Bids received for each LA.

All of the Intra-Round Bids submitted during the auction will be preserved, and may be determined to be winning bids. Therefore, bidders are responsible for payment of the bids they submit and may be held accountable for up to the maximum amount of any Intra-Round Bids or live bids determined to be winning bids during the final award procedures.

Determining Provisional Winners

After the bidding ends, BOEM will determine the provisionally winning bids in accordance with the process described in this section. This process consists of two stages: Stage 1 and Stage 2, which are described herein. Once the auction itself ends, nothing further is required of bidders within or between Stages 1 and 2. In practice, the stages of the process will take place as part of the solution algorithm for analyzing the monetary and credit portion of the bids, determining provisional winners, finding the LAs won by the provisional winners, and calculating the applicable bid prices to be paid by the winners for the LAs they won. This evaluation will be reviewed, checked, and validated by the panel. The determination of provisional winners, in both stages, will be based on the two auction variables, as well as on a bidder's adherence to the rules of the auction, and the absence of conduct detrimental to the integrity of the competitive auction.

• *Stage 1*

Live bids submitted in the final round of the auction are Qualified Bids. In Stage 1, a bidder with a Qualified Bid is provisionally assured of winning the LA(s) included in its final round bid, regardless of any other prior-to-final round live bids or Intra-Round Bids in any round. If all LAs are awarded to bidders in Stage 1, the second award stage is not necessary. If any LA received a bid but was not awarded in Stage 1 because no live bids were received in the final round of the auction, BOEM will proceed to Stage 2 to award the leases.

Following the auction, all winning bidders must pay the price associated with their winning bids, which may consist of cash and non-monetary credits or just cash.

• *Stage 2*

All bids are either Qualified Bids or Contingent Bids. Contingent bids are all live bids received before the final round, and any Intra-Round Bids received during the auction. In Stage 2, BOEM will consider Contingent Bids to see if the non-awarded LA(s) can be awarded without interfering with Stage 1 awards. BOEM will award leases in Stage 2 to the bid(s) that maximize(s) the total As-Bid prices.

Any Contingent Bids that conflict with Qualified Bids will not be considered. There is one notable exception to this rule. This exception allows BOEM to accept a Contingent Bid for a combination of LAs notwithstanding the existence of a Qualified Bid, provided the acceptance of the Contingent Bid for these LAs results in higher overall As-Bid prices than acceptance of only the Qualified Bid. In this scenario, a bidder would be awarded the LAs included in the Contingent Bid and would be required to pay its live bid price or its Intra-Round Bid price for those LAs included in the Contingent Bid.

This exception represents the only situation in which BOEM will consider for award a Contingent Bid which overlaps a Qualified Bid. In contrast, there is no situation in which one bidder's Contingent Bid will be considered for award if it overlaps with any LA that is included in another bidder's Qualified Bid.

Under certain circumstances, different combinations of Contingent Bids may result in the same total As-Bid price. In such cases, BOEM will resolve the resulting tie with a random drawing.

In the event a bidder submits a bid for a LA that the panel and BOEM determine to be a winning bid, the bidder will be expected to sign the applicable lease documents in a timely manner and submit the full cash payment due, pursuant to 30 CFR 585.224. If a bidder fails to timely sign and pay for the lease, then BOEM will not issue the lease to that bidder, and the bidder will forfeit its bid deposit. BOEM may consider failure of a bidder to timely pay the full amount due an indication that the bidder is no longer financially qualified to participate in other lease sales under BOEM's regulations at 30 CFR 585.106 and 585.107.

Credit Factors

Shortly before the auction, BOEM will convene a panel (as provided in BOEM's regulations, discussed above) to evaluate bidders' non-monetary packages to determine whether and to what extent each bidder is eligible for a non-monetary credit applicable to the As-Bid auction price for one of the LAs in each round of the auction, as described herein. In order to receive a credit for a PPA or a CBA, a bidder must be legally, technically and financially eligible to acquire a commercial OCS wind lease, and must not be affiliated with any other bidding entity also seeking credit for the same PPA or CBA.

The percentage credit that will be applicable to each bidder throughout the auction and award process is determined based on the panel's evaluation of required documentation submitted by the bidders as of the deadline specified in the FSN. Bidders will be informed by email before the monetary auction about the percentage credit applicable to their bids. A bidder may not receive more than one bid credit, and the bid credit will be applicable to only one LA. Any non-monetary credit would only be applicable to the highest priced LA in a bid for multiple LAs. For an Intra-Round Bid containing multiple LAs, the highest priced LA will be determined using the previous round's asking prices. In each round, the auction system will display to each bidder information showing how their As-Bid auction prices are affected by the credit imputed to their bid to determine their net monetary payment due to BOEM, should their bids prevail as winning bids in the award stages. Application of the credit percentage to the appropriate As-Bid auction price will be rounded to the nearest whole dollar amount.

The bidder's credit percentage is limited to the greater of 5% for a CBA or up to 25% for a PPA. This credit percentage will be applied to the highest priced LA related to the bidder's latest live bid or Intra-Round Bid. In the case of an Intra-Round Bid for multiple LAs, the credit will apply only to the highest-priced LA, but the applicable price for calculating the credit will be based on the previous round's asking prices, not on any additional amount above the previous round's asking prices as reflected in the incremental amount associated with its Intra-Round Bid.

The panel will review the non-monetary package submitted by each bidder and, based on the criteria provided in the FSN for a CBA and PPA, determine whether bidders have established that they are qualified to receive a credit, and the percentage at which that credit will apply. If the panel determines that no bidder has qualified for a non-monetary factor, the auction will proceed with each bidder registered with no imputed credit.

Credit Factor Definitions

The definitions herein will apply to the factors for which bidders may earn a credit.

Community Benefits Agreements (CBA). BOEM proposes a 5% credit in the monetary phase of the auction to any bidder that can demonstrate that it has executed a CBA, as defined in this section. BOEM is proposing this non-monetary factor and credit in response to comments requesting CBAs be recognized in the multiple-factor auction format received in response to notices associated with the Massachusetts planning and environmental review process. BOEM received comments recommending that a non-monetary factor for CBAs be given a larger percent credit than 5%. BOEM, however, believes that the 5% credit fairly represents the value associated with CBAs that meet the criteria described in this notice. In particular, these criteria, while recognizing the contribution a CBA may provide to the ultimate success of a project, may not require substantial financial consideration in support of the project. For this reason, BOEM has not proposed a larger percentage credit for this non-monetary factor.

In order for a non-monetary package to qualify for a 5% credit in this auction, the BOEM-appointed panel must answer yes to the following questions:

1. Is there a legally binding contract?
2. Is the contract between:
a. A bidder; and
b. One or more community-based organizations (CBO)?
3. Has the bidder committed to provide specified community benefits?
4. Has the CBO committed in specific ways to support the project in the governmental approval process?

A community-based organization (CBO) is defined as: A legally incorporated organization whose membership includes residents or property owners of a community within the potentially affected region, the local government of the community, or an entity created or managed by the local government(s) of the community or communities.

Bidders seeking non-monetary credit for a CBA will be required to submit the CBA as part of their non-monetary package by the date specified in the FSN. In addition, bidders must include a description of how the CBA meets the requirements outlined in the FSN. For protection of confidential business information, please see the section entitled ''Protection of Privileged or Confidential Information'' in this notice.

Power purchase agreement (PPA) is any legally enforceable long-term contract negotiated between an electricity generator (Generator) and a power purchaser (Buyer) that identifies, defines, and stipulates the rights and obligations of one party to produce, and the other party to purchase, energy from an offshore wind project to be located in the lease sale area. The PPA must state that the Generator will sell to the Buyer and the Buyer will buy from the Generator capacity, energy, and/or the environmental attributes generated by the project, as defined in the terms and conditions set forth in the PPA. Energy products to be supplied by the Generator and the details of the firm cost recovery mechanism approved by the state's public utility commission or other applicable authority used to recover expenditures incurred as a result of the PPA must be specified in the PPA. To qualify, a PPA must contain the following terms or supporting documentation:

(i) A complete description of the proposed project;

(ii) Identification of both the electricity Generator and Buyer that will enter into a long term contract;

(iii) A time line for permitting, licensing, and construction;

(iv) Pricing projected under the long term contract being sought, including prices for all market products that would be sold under the proposed long term contract;

(v) A schedule of quantities of each product to be delivered and projected electrical energy production profiles;

(vi) The term for the long-term contract;

(vii) Citations to all filings related to the PPA that have been made with state and Federal agencies, and identification of all such filings that are necessary to be made; and

(viii) Copies of or citations to interconnection filings related to the PPA.

If the panel determines a bidder has executed a PPA for at least 250 MW, it will be eligible for the entire 25% credit. If the panel determines a bidder has executed a PPA for an amount less than 250 MW, the bidder may still be eligible for a non-monetary credit proportional to the PPA's fraction of 250 MW. The smaller percentage for a partial credit will be calculated according to the formula below:

$$\text{Partial Credit} = \frac{(\text{Full Credit} * \text{Partial PPA})}{\text{Full PPA}}$$

Where:

- Partial Credit = Percent credit for which a smaller PPA is eligible.
- Full PPA = 250 MW
- Full Credit = 25%
- Partial PPA = amount (less than 250 MW) of power under contract

Additional Information Regarding the Auction Format

Non-Monetary Auction Procedures

All bidders seeking a non-monetary auction credit will be required to submit a non-monetary auction package prior to the auction. Instructions and deadlines for submittal will be provided in the FSN. If a bidder does not submit a non-monetary package by the date specified in the FSN, then BOEM will assume that bidder is not seeking a non-monetary auction credit and the panel will not consider that bidder for a non-monetary auction credit.

Bidder Authentication

Prior to the auction, the Auction Manager will send several bidder authentication packages to each bidder shortly after BOEM has processed the BFFs. One package will contain tokens for each authorized individual. Tokens are digital authentication devices. The tokens will be mailed to the Primary Point of Contact indicated on the BFF. This individual is responsible for distributing the tokens to the individuals authorized to bid for that company. Bidders are to ensure that each token is returned within three business days following the auction. An addressed, stamped envelope will be provided to facilitate this process. In the event that a bidder fails to submit a BFF or a bid deposit, or does not participate in the auction, BOEM will de-activate that bidder's token and login information, and the bidder will be asked to return its tokens.

The second package contains login credentials for authorized bidders. The login credentials will be mailed to the address provided in the BFF for each authorized individual. Bidders can confirm these addresses by calling (703) 787–1320. This package will contain user login information and instructions for accessing the Auction System Technical Supplement and Alternative Bidding Form. The login information,

along with the tokens, will be tested during the Mock Auction.

Monetary Auction Times

Specific information regarding when the bidders can enter the auction system and the auction start time will be provided in the FSN. Additional information will be made available in an Auction System Technical Supplement, which will be posted on BOEM's Web site prior to the auction.

BOEM and the auction contractors will use the auction platform messaging service to keep bidders informed on issues of interest during the auction. For example, BOEM may change the schedule at any time, including during the auction. If BOEM changes the schedule during the auction, it will use the messaging feature to notify bidders that a revision has been made, and direct bidders to the relevant page. BOEM will also use the messaging system for other changes and items of particular note during the auction. The auction schedule and asking price increments are in BOEM's discretion, and are subject to change at any time before or during the auction.

During the auction, bidders may place bids at any time during the round. At the top of the bidding page, a countdown clock will show how much time remains in the round. Bidders have until the scheduled time to place bids. Bidders should place bids according to the procedures described in the Auction System Technical Supplement, and as practiced at the Mock Auction. No information about the round is available until the round has closed and results have been posted, so there should be no strategic advantage to placing bids early or late in the round.

Alternate Bidding Procedures

Any bidder who is unable to place a bid using the online auction and would be interested in placing a bid using the Alternate Bidding Procedures must call BOEM/the BOEM Auction Manager at the help desk number that is listed in the Auction System Technical Supplement before the end of the round. BOEM will authenticate the caller to ensure he/she is authorized to bid on behalf of the company. The bidder must explain to the BOEM Auction Manager the reasons for which he/she is forced to place a bid using the Alternate Bidding Procedure. At that time, BOEM may, in its sole discretion, permit or refuse to accept a request for the placement of a bid using the Alternative Bidding Procedure.

The Alternative Bidding Procedure enables a bidder who is having difficulties accessing the Internet to submit its bid via an Alternative Bidding Form that must be faxed to the Auction Manager. If the bidder has not placed a bid, but calls BOEM before the end of the round and notifies BOEM that it is preparing a bid using the Alternate Bidding Procedure, and submits the Alternate Bidding Form by fax before the round ends, BOEM will likely accept the bid, though acceptance or rejection of the bid is within BOEM's sole discretion. If the bidder calls during the round, but does not submit the bid until after the round ends (but before the round is posted), BOEM may or may not accept the bid, in part based on how much time remains in the recess. Bidders are strongly encouraged to submit the Alternative Bidding Form before the round ends. If the bidder calls during the recess following the round, but before the previous round's results have been posted, BOEM will likely reject its bid, even if it has otherwise complied with all of BOEM's Alternate Bidding Procedures. If the bidder calls to enter a bid after results have been posted, BOEM will reject the bid.

Except for bidders who have uncontested bids in the current round, failure to place a bid during a round will be interpreted as dropping out of the auction. Bids in all rounds are preserved for consideration in Stage 2 of the award process. Bidders are held accountable for all bids placed during the auction. This is true if they continued bidding in the last round, if they placed an Intra-Round Bid in an earlier round, or if they stopped bidding during the auction.

Acceptance, Rejection, or Return of Bids: BOEM reserves the right and authority to reject any and all bids. No leases will be awarded to any bidders and no bids will be accepted, unless (1) the bidder has complied with all requirements of the FSN, applicable regulations and statutes, including, among others, those related to bidder qualifications, bid deposits, and adherence to the integrity of the competitive bidding process, (2) the bid conforms with the requirements and rules of the auction, and (3) the amount of the bid has been determined to be adequate by the authorized officer. Any bid submitted that does not satisfy these requirements may be returned to the bidder by the Program Manager of BOEM's Office of Renewable Energy Programs and, in that case, would not be considered for acceptance.

Process for Issuing the Leases: If BOEM proceeds with lease issuance, it will issue three unsigned copies of the lease form to each winning bidder. Within 10 business days after receiving the lease copies, a winning bidder must:

1. Execute the lease on the bidder's behalf;
2. File financial assurance as required under 30 CFR 585.515–537; and
3. Pay by electronic funds transfer (EFT) the balance of the bonus bid (bid amount less the bid deposit). BOEM requires bidders to use EFT procedures (not to include *pay.gov*) for payment of the balance of the bonus bid, following the detailed instructions contained in the ''Instructions for Making Electronic Payments'' available on BOEM's Web site at: *http://www.boem.gov/Renewable- Energy-Program/State-Activities/Massachusetts.aspx*.

If a winning bidder does not meet these three requirements within 10 business days of receiving the lease copies as described herein, or if a winning bidder otherwise fails to comply with applicable regulations or the terms of the FSN, the winning bidder will forfeit its bid deposit. BOEM may extend this 10 business-day time period if it determines the delay was caused by events beyond the winning bidder's control.

In the event that the provisional winner does not execute and return the leases according to the instructions in the FSN, BOEM reserves the right to reconvene the panel to determine whether it is possible to identify a bid that would have won in the absence of the bid previously determined to be the winning bid. In the event that a new winning bid is selected by the panel, BOEM will follow the procedures in this section for the new winner(s).

BOEM will not execute a lease until (1) the three requirements above have been satisfied, (2) BOEM has accepted the winning bidder's financial assurance, and (3) BOEM has processed the winning bidder's payment. The winning bidder may meet financial assurance requirements by posting a surety bond or by setting up an escrow account with a trust agreement giving BOEM the right to withdraw the money held in the account on demand. BOEM may accept other forms of financial assurance on a case-by-case basis in accordance with its regulations. BOEM encourages provisionally winning bidders to discuss the financial assurance requirement with BOEM as soon as possible after the auction has concluded.

Within 45 days of the date that the winning bidder receives the lease copies, the winning bidder must pay the first year's rent using the *pay.gov* Renewable Energy Initial Rental Payment Form available at: *https://pay.gov/paygov/forms/formInstance.html?agencyFormId=27797604*.

Anti-Competitive Behavior: In addition to the auction rules described in this notice, bidding behavior is governed by Federal antitrust laws designed to prevent anticompetitive behavior in the marketplace. Compliance with BOEM's auction procedures will not insulate a party from enforcement of antitrust laws.

In accordance with the Act at 43 U.S.C. 1337(c), following the auction, and before the acceptance of bids and the issuance of leases, BOEM will ''allow the Attorney General, in consultation with the Federal Trade Commission, thirty days to review the results of the lease sale.'' If a bidder is found to have engaged in anti-competitive behavior or otherwise violated BOEM's rules in connection with its participation in the competitive bidding process, BOEM may reject the high bid.

Anti-competitive behavior determinations are fact specific. However, such behavior may manifest itself in several different ways, including, but not limited to:

- An agreement, either express or tacit, among bidders to not bid in an auction, or to bid a particular price;
- An agreement among bidders not to bid for a particular LA;
- An agreement among bidders not to bid against each other; and
- Other agreements among bidders that have the effect of limiting the final auction price.

BOEM may decline to award a lease if, pursuant to the Act (43 U.S.C. 1337(c)), it is determined by the Attorney General in consultation with the Federal Trade Commission that doing so would be inconsistent with antitrust laws (e.g., heavily concentrated market, etc.).

For more information on whether specific communications or agreements could constitute a violation of Federal antitrust law, please see: *http://www.justice.gov/atr/public/business-resources.html*, or consult counsel.

Bidder's Financial Form Certification: Each bidder is required to sign the self-certification, in accordance with 18 U.S.C. 1001 (Fraud and False Statements) in the Bidder's Financial Form, which can be found on BOEM's Web site at: *http://www.boem.gov/Renewable-Energy-Program/State-Activities/Massachusetts.aspx*. The form must be filled out and returned to BOEM in accordance with the ''Deadlines and Milestones for Bidders'' section of this notice.

Non-Procurement Debarment and Suspension Regulations: Pursuant to regulations at 43 CFR Part 42, Subpart C, an OCS renewable energy Lessee must comply with the U.S. Department of the Interior's non-procurement debarment and suspension regulations at 2 CFR 180 and 1400 and agree to communicate the requirement to comply with these regulations to persons with whom the Lessee does business as it relates to this lease by including this term as a condition in their contracts and other transactions.

Final Sale Notice: BOEM will consider comments received or postmarked during the PSN comment period in preparing a FSN that will provide the final details concerning the offering and issuance of OCS commercial wind energy leases in the Massachusetts WEA. The FSN will be published in the **Federal Register** at least 30 days before the lease sale is conducted and will provide the date and time of the auction.

Force Majeure: The Program Manager of BOEM's Office of Renewable Energy Programs has the discretion to change any date, time, and/or location specified in the FSN in case of a force majeure event that the Program Manager deems may interfere with a fair and proper lease sale process. Such events may include, but are not limited to, natural disasters (e.g., earthquakes, hurricanes, floods), wars, riots, acts of terrorism, fire, strikes, civil disorder, or other events of a similar nature. In case of such events, bidders should call (703) 787–1300 or access the BOEM Web site at: *http://www.boem.gov/Renewable-Energy-Program/index.aspx.*

Appeals: The appeals procedures are provided in BOEM's regulations at 30 CFR 585.225 and 585.118(c). Pursuant to 30 CFR 585.225.

(a) If BOEM rejects your bid, BOEM will provide a written statement of the reasons and refund any money deposited with your bid, without interest.

(b) You will then be able to ask the BOEM Director for reconsideration, in writing, within 15 business days of bid rejection, under 30 CFR 585.118(c)(1). BOEM will send you a written response either affirming or reversing the rejection.

The procedures for appealing final decisions with respect to lease sales are described in 30 CFR 585.118(c).

Protection of Privileged or Confidential Information

BOEM will protect privileged or confidential information that is submitted as required by the Freedom of Information Act (FOIA). Exemption 4 of FOIA applies to trade secrets and commercial or financial information that is privileged or confidential. If you wish to protect the confidentiality of such information, clearly mark it and request that BOEM treat it as confidential. BOEM will not disclose such information, except as required by FOIA. Please label privileged or confidential information ''Contains Confidential Information'' and consider submitting such information as a separate attachment.

However, BOEM will not treat as confidential any aggregate summaries of such information or comments not containing such information. Additionally, BOEM may not treat as confidential the legal title of the commenting entity (e.g., the name of a company). Information that is not labeled as privileged or confidential will be regarded by BOEM as suitable for public release.

Section 304 of the National Historic Preservation Act (16 U.S.C. 470w–3(a))

BOEM is required, after consultation with the Secretary of the Department of the Interior, to withhold the location, character, or ownership of historic resources if it determines that disclosure may, among other things, cause a significant invasion of privacy, risk harm to the historic resources or impede the use of a traditional religious site by practitioners. Tribal entities and other interested parties should designate information that they wish to be held as confidential and provide the reasons why BOEM should do so.

Dated: May 30, 2014.

Walter D. Cruickshank,

Acting Director, Bureau of Ocean Energy Management.

[FR Doc. 2014–14116 Filed 6–17–14; 8:45 am]

BILLING CODE 4310–MR–P

DEPARTMENT OF THE INTERIOR

Bureau of Ocean Energy Management

[Docket No. BOEM–2014–0011; MMAA104000]

Commercial Wind Lease Issuance and Site Assessment Activities on the Atlantic Outer Continental Shelf (OCS) Offshore Massachusetts

AGENCY: Bureau of Ocean Energy Management (BOEM), Interior.

ACTION: Notice of the Availability of a Revised Environmental Assessment (EA) and a Finding of No Significant Impact (FONSI).

SUMMARY: BOEM has prepared a revised EA considering the reasonably foreseeable environmental and socioeconomic effects of issuing renewable energy leases and lessees' subsequent site characterization

activities (e.g., geophysical, geotechnical, archaeological, and biological surveys) and site assessment activities (including the installation and operation of meteorological towers and buoys) on those leases that may be issued in the Wind Energy Area (WEA) on the OCS offshore Massachusetts (MA). The purpose of this notice is to inform the public of the availability of the revised EA and FONSI, which can be accessed online at: *http://www.boem.gov/State-Activities-Massachusetts*.

In accordance with the requirements of the National Environmental Policy Act (NEPA) and the Council on Environmental Quality's (CEQ) regulations implementing NEPA at 40 CFR 1500–1508, BOEM issued a FONSI supported by the analysis in the revised EA. The FONSI concluded that the reasonably foreseeable environmental impacts associated with the proposed action and alternatives, as set forth in the EA, would not significantly impact the quality of the human environment; therefore, the preparation of an Environmental Impact Statement (EIS) is not required.

Authority: This notice is published pursuant to 43 CFR 46.305.

FOR FURTHER INFORMATION CONTACT: Michelle Morin, BOEM Office of Renewable Energy Programs, 381 Elden Street, HM 1328, Herndon, Virginia 20170–4817, (703) 787–1340 or *michelle.morin@boem.gov*.

SUPPLEMENTARY INFORMATION: On November 2, 2012, BOEM published a Notice of Availability (NOA) of an EA, requesting public comment on alternatives considered in that 2012 EA. In addition, comments were requested on measures to mitigate impacts to environmental resources and socioeconomic conditions that could potentially occur in the MA WEA and surrounding areas as a result of leasing, site characterization, and site assessment activities in those areas (77 FR 66185).

The 2012 EA considered the impacts that could result from leasing the entire MA WEA and BOEM's approval of site assessment plans within that area. Comments received in response to the 2012 NOA can be viewed at: *http://www.regulations.gov* by searching for Docket ID BOEM–2012–0086.

Based on comments received on the 2012 EA, and results of required consultations (e.g., Endangered Species Act), BOEM revised the 2012 EA. BOEM will use this revised EA to inform decisions to issue leases in the MA WEA, and to subsequently approve Site Assessment Plans (SAPs) on those leases. BOEM may issue one or more commercial wind energy leases in the MA WEA. The competitive lease process is set forth at 30 CFR 585.210–585.225.

A commercial lease gives the lessee the exclusive right to seek BOEM approval for the development of the leasehold. The lease does not grant the lessee the right to construct any facilities; rather, the lease grants the lessee the right to use the leased area to develop its plans, which BOEM must approve before the lessee may proceed to the next stage of the process. *See* 30 CFR 585.600 and 585.601. In the event that a particular lease is issued, and the lessee submits a SAP, BOEM would then determine whether the revised EA adequately considers the environmental consequences of the activities proposed in the lessee's SAP. If BOEM determines that the analysis in the revised EA adequately considers these consequences, then no further analysis under NEPA would be required and BOEM could approve the SAP. If, on the other hand, BOEM determines that the analysis in this revised EA is inadequate for that purpose, BOEM would prepare additional NEPA analysis before it could approve the SAP.

If a lessee is prepared to propose a wind energy generation facility on its lease, it would submit a Construction and Operations Plan (COP). BOEM then would prepare a separate site- and project-specific NEPA analysis of the proposed project. This analysis would likely take the form of an EIS in which BOEM would evaluate the reasonably foreseeable environmental and socioeconomic consequences of the proposed project. The EIS would provide the public and Federal officials with comprehensive information regarding the reasonably foreseeable environmental impacts of the proposed project and would inform BOEM's decision to approve, approve with modification, or disapprove a lessee's COP pursuant to 30 CFR 585.628. This process would include additional opportunities for public involvement pursuant to NEPA.

Dated: June 10, 2014.

Walter D. Cruickshank,

Acting Director, Bureau of Ocean Energy Management.

[FR Doc. 2014–14004 Filed 6–17–14; 8:45 am]

BILLING CODE 4310–MR–P

INTERNATIONAL TRADE COMMISSION

[Investigation Nos. 731–TA–1229–1230 (Final)]

Monosodium Glutamate From China and Indonesia; Scheduling of the Final Phase of the Antidumping Duty Investigations

AGENCY: United States International Trade Commission.

ACTION: Notice.

SUMMARY: The Commission hereby gives notice of the scheduling of the final phase of antidumping duty investigation nos. 731–TA–1229–1230 (Final) under section 735(b) of the Tariff Act of 1930 (19 U.S.C. 1673d(b)) (the Act) to determine whether an industry in the United States is materially injured or threatened with material injury, or the establishment of an industry in the United States is materially retarded, by reason of less-than-fair-value imports from China and Indonesia of monosodium glutamate, provided for in subheading 2922.42.10 of the Harmonized Tariff Schedule of the United States.[1]

For further information concerning the conduct of this phase of the investigations, hearing procedures, and rules of general application, consult the Commission's Rules of Practice and Procedure, part 201, subparts A through E (19 CFR part 201), and part 207, subparts A and C (19 CFR part 207).

DATES: *Effective Date:* Thursday, May 8, 2014.

FOR FURTHER INFORMATION CONTACT: Amy Sherman (202–205–3289), Office of Investigations, U.S. International Trade Commission, 500 E Street SW., Washington, DC 20436. Hearing-impaired persons can obtain information on this matter by contacting the Commission's TDD terminal on 202–205–1810. Persons with mobility impairments who will need special

[1] For purposes of these investigations, the Department of Commerce has defined the subject merchandise as ''monosodium glutamate (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 this scope when the resulting mix contains 15% 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 this investigation regardless of physical form (including, but not limited to, substrates, solutions, dry powders of any particle size, or unfinished forms such as MSG slurry), end-use application, or packaging. MSG has a molecular formula of C5H8NO4Na, a Chemical Abstract Service (CAS) registry number of 6106–04–3, and a Unique Ingredient Identifier (UNII) number of W81N5U6R6U.''

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 (*http://www.usitc.gov*). The public record for these investigations may be viewed on the Commission's electronic docket (EDIS) at *http://edis.usitc.gov.*

SUPPLEMENTARY INFORMATION:

Background.—The final phase of these investigations is being scheduled as a result of affirmative preliminary determinations by the Department of Commerce that imports of monosodium glutamate from China and Indonesia are being sold in the United States at less than fair value within the meaning of section 733 of the Act (19 U.S.C. 1673b). The investigation was requested in a petition filed on September 16, 2013 by Ajinomoto North America Inc. (''AJINA''), Itasca, Illinois.

Participation in the investigations and public service list.—Persons, including industrial users of the subject merchandise and, if the merchandise is sold at the retail level, representative consumer organizations, wishing to participate in the final phase of these investigations as parties must file an entry of appearance with the Secretary to the Commission, as provided in section 201.11 of the Commission's rules, no later than 21 days prior to the hearing date specified in this notice. A party that filed a notice of appearance during the preliminary phase of the investigations need not file an additional notice of appearance during this final phase. The Secretary will maintain a public service list containing the names and addresses of all persons, or their representatives, who are parties to the investigations.

Limited disclosure of business proprietary information (BPI) under an administrative protective order (APO) and BPI service list.—Pursuant to section 207.7(a) of the Commission's rules, the Secretary will make BPI gathered in the final phase of these investigations available to authorized applicants under the APO issued in the investigations, provided that the application is made no later than 21 days prior to the hearing date specified in this notice. Authorized applicants must represent interested parties, as defined by 19 U.S.C. 1677(9), who are parties to the investigations. A party granted access to BPI in the preliminary phase of the investigations need not reapply for such access. A separate service list will be maintained by the Secretary for those parties authorized to receive BPI under the APO.

Staff report.—The prehearing staff report in the final phase of these investigations will be placed in the nonpublic record on Monday, September 8, 2014, and a public version will be issued thereafter, pursuant to section 207.22 of the Commission's rules.

Hearing.—The Commission will hold a hearing in connection with the final phase of these investigations beginning at 9:30 a.m. on Tuesday, September 23, 2014, at the U.S. International Trade Commission Building. Requests to appear at the hearing should be filed in writing with the Secretary to the Commission on or before Wednesday, September 17, 2014. A nonparty who has testimony that may aid the Commission's deliberations may request permission to present a short statement at the hearing. All parties and nonparties desiring to appear at the hearing and make oral presentations should attend a prehearing conference to be held at 9:30 a.m. on Friday, September 19, 2014, at the U.S. International Trade Commission Building. Oral testimony and written materials to be submitted at the public hearing are governed by sections 201.6(b)(2), 201.13(f), and 207.24 of the Commission's rules. Parties must submit any request to present a portion of their hearing testimony *in camera* no later than 7 business days prior to the date of the hearing.

Written submissions.—Each party who is an interested party shall submit a prehearing brief to the Commission. Prehearing briefs must conform with the provisions of section 207.23 of the Commission's rules; the deadline for filing is Monday, September 15, 2014. Parties may also file written testimony in connection with their presentation at the hearing, as provided in section 207.24 of the Commission's rules, and posthearing briefs, which must conform with the provisions of section 207.25 of the Commission's rules. The deadline for filing posthearing briefs is Tuesday, September 30, 2014. In addition, any person who has not entered an appearance as a party to the investigations may submit a written statement of information pertinent to the subject of the investigations, including statements of support or opposition to the petition, on or before Tuesday, September 30, 2014. On Thursday, October 16, 2014, the Commission will make available to parties all information on which they have not had an opportunity to comment. Parties may submit final comments on this information on or before Monday, October 20, 2014, but such final comments must not contain new factual information and must otherwise comply with section 207.30 of the Commission's rules. All written submissions must conform with the provisions of section 201.8 of the Commission's rules; any submissions that contain BPI must also conform with the requirements of sections 201.6, 207.3, and 207.7 of the Commission's rules. The Commission's *Handbook on E-Filing,* available on the Commission's Web site at *http://edis.usitc.gov,* elaborates upon the Commission's rules with respect to electronic filing.

Additional written submissions to the Commission, including requests pursuant to section 201.12 of the Commission's rules, shall not be accepted unless good cause is shown for accepting such submissions, or unless the submission is pursuant to a specific request by a Commissioner or Commission staff.

In accordance with sections 201.16(c) and 207.3 of the Commission's rules, each document filed by a party to the investigations must be served on all other parties to the investigations (as identified by either the public or BPI service list), and a certificate of service must be timely filed. The Secretary will not accept a document for filing without a certificate of service.

Authority: These investigations are being conducted under authority of title VII of the Tariff Act of 1930; this notice is published pursuant to section 207.21 of the Commission's rules.

By order of the Commission.

Issued: June 12, 2014.

Lisa R. Barton,

Secretary to the Commission.

[FR Doc. 2014–14229 Filed 6–17–14; 8:45 am]

BILLING CODE 7020–02–P

INTERNATIONAL TRADE COMMISSION

[Investigation No. 731–TA–1145 (Review)]

Steel Threaded Rod From China; Scheduling of an Expedited Five-Year Review

AGENCY: United States International Trade Commission.

ACTION: Notice.

SUMMARY: The Commission hereby gives notice of the scheduling of an expedited review pursuant to section 751(c)(3) of the Tariff Act of 1930 (19 U.S.C. 1675(c)(3)) (the Act) to determine whether revocation of the antidumping duty order on steel threaded rod from China would be likely to lead to continuation or recurrence of material injury within a reasonably foreseeable

time. For further information concerning the conduct of this review and rules of general application, consult the Commission's Rules of Practice and Procedure, part 201, subparts A through E (19 CFR part 201), and part 207, subparts A, D, E, and F (19 CFR part 207).

DATES: *Effective Date:* June 6, 2014.

FOR FURTHER INFORMATION CONTACT: Fred Ruggles (202–205–3187), Office of Investigations, U.S. International Trade Commission, 500 E Street SW., Washington, DC 20436. Hearing-impaired persons can obtain information on this matter 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 (*http://www.usitc.gov*). The public record for this review may be viewed on the Commission's electronic docket (EDIS) at *http://edis.usitc.gov.*

SUPPLEMENTARY INFORMATION:

Background.—On Friday, June 6, 2014, the Commission determined that the domestic interested party group response to its notice of institution (79 FR 11827, March 3, 2014) of the subject five-year review was adequate and that the respondent interested party group response was inadequate. The Commission did not find any other circumstances that would warrant conducting a full review.[1] Accordingly, the Commission determined that it would conduct an expedited review pursuant to section 751(c)(3) of the Act.

Staff report.—A staff report containing information concerning the subject matter of the review will be placed in the nonpublic record on Wednesday, July 2, 2014, and made available to persons on the Administrative Protective Order service list for this review. A public version will be issued thereafter, pursuant to section 207.62(d)(4) of the Commission's rules.

Written submissions.—As provided in section 207.62(d) of the Commission's rules, interested parties that are parties to the review and that have provided individually adequate responses to the notice of institution,[2] and any party other than an interested party to the review may file written comments with the Secretary on what determination the Commission should reach in the review. Comments are due on or before Tuesday, July 8, 2014 and may not contain new factual information. Any person that is neither a party to the five-year review nor an interested party may submit a brief written statement (which shall not contain any new factual information) pertinent to the review by Tuesday, July 8, 2014. However, should the Department of Commerce extend the time limit for its completion of the final results of its review, the deadline for comments (which may not contain new factual information) on Commerce's final results is three business days after the issuance of Commerce's results. If comments contain business proprietary information (BPI), they must conform with the requirements of sections 201.6, 207.3, and 207.7 of the Commission's rules. Please be aware that the Commission's rules with respect to electronic filing have been amended. The amendments took effect on November 7, 2011. See 76 FR 61937 (Oct. 6, 2011) and the revised Commission's Handbook on E-Filing, available on the Commission's Web site at *http://edis.usitc.gov*.

In accordance with sections 201.16(c) and 207.3 of the rules, each document filed by a party to the review must be served on all other parties to the review (as identified by either the public or BPI service list), and a certificate of service must be timely filed. The Secretary will not accept a document for filing without a certificate of service.

Authority: This review is being conducted under authority of title VII of the Tariff Act of 1930; this notice is published pursuant to section 207.62 of the Commission's rules.

By order of the Commission.

Issued: June 12, 2014.

Lisa R. Barton,

Secretary to the Commission.

[FR Doc. 2014–14185 Filed 6–17–14; 8:45 am]

BILLING CODE 7020–02–P

[1] A record of the Commissioners' votes, the Commission's statement on adequacy, and any individual Commissioner's statements will be available from the Office of the Secretary and at the Commission's Web site.

[2] The Commission has found the responses submitted by All America Threaded Products, Inc., Bay Standard Manufacturing, Inc., and Vulcan Threaded Products, Inc. to be individually adequate. Comments from other interested parties will not be accepted (*see* 19 CFR 207.62(d)(2)).

INTERNATIONAL TRADE COMMISSION

[USITC SE–14–021]

Government in the Sunshine Act Meeting Notice

AGENCY HOLDING THE MEETING: United States International Trade Commission.

TIME AND DATE: June 24, 2014 at 11:00 a.m.

PLACE: Room 101, 500 E Street SW., Washington, DC 20436, Telephone: (202) 205–2000.

STATUS: Open to the public.

MATTERS TO BE CONSIDERED:

1. Agendas for future meetings: None.
2. Minutes.
3. Ratification List.
4. Vote in Inv. Nos. 731–TA–1210–1212 (Final) (Welded Stainless Steel Pressure Pipe from Malaysia, Thailand, and Vietnam). The Commission is currently scheduled to complete and file its determinations and views of the Commission on July 7, 2014.
5. Vote in Inv. Nos. 701–TA–454 and 731–TA–1144 (Review) (Welded Stainless Steel Pressure Pipe from China). The Commission is currently scheduled to complete and file its determinations and views of the Commission on July 7, 2014.
6. Outstanding action jackets: none.

In accordance with Commission policy, subject matter listed above, not disposed of at the scheduled meeting, may be carried over to the agenda of the following meeting.

By order of the Commission.

Issued: June 12, 2014.

William R. Bishop,

Supervisory Hearings and Information Officer.

[FR Doc. 2014–14327 Filed 6–16–14; 11:15 am]

BILLING CODE 7020–02–P

DEPARTMENT OF JUSTICE

Notice of Lodging Proposed Consent Decree

In accordance with Departmental Policy, 28 CFR 50.7, notice is hereby given that a proposed Consent Decree in *United States* v. *St. Marys Railway West LLC and Claudius R. Strickland,* Civil Action No. 5:13-cv-0028–LGW–JEG, was lodged with the United States District Court for the Southern District of Georgia on June 11, 2014.

The proposed Consent Decree concerns a complaint filed by the United States against St. Marys Railway West LLC and Claudius R. Strickland, pursuant to Sections 402 and 404 of the Clean Water Act, 33 U.S.C. 1342 and 1344, to obtain injunctive relief from and impose civil penalties against the Defendants for violating the Clean Water Act by discharging pollutants without a permit into waters of the United States. The proposed Consent Decree resolves these allegations by requiring the Defendants to pay for mitigation and to pay a civil penalty.

The Department of Justice will accept written comments relating to the proposed Consent Decree for thirty (30) days from the date of publication of this Notice. Please address comments to Paul Cirino, Environmental Defense Section, United States Department of Justice, Post Office Box 7611, Washington, DC 20044–7611 and refer to *United States* v. *St. Marys Railway West LLC and Claudius R. Strickland,* DJ # 90–5–1–1–18821.

The proposed Consent Decree may be examined at any of the Clerk's Offices, United States District Court for the Southern District of Georgia, including the location at 601 Tebeau Street, Waycross, GA 31501. In addition, the proposed Consent Decree may be examined electronically at *http://www.justice.gov/enrd/Consent_Decrees.html.*

Cherie L. Rogers,

Assistant Section Chief, Environmental Defense Section, Environment and Natural Resources Division.

[FR Doc. 2014–14195 Filed 6–17–14; 8:45 am]

BILLING CODE 4410–15–P

DEPARTMENT OF LABOR

Office of the Secretary

Agency Information Collection Activities; Submission for OMB Review; Comment Request; Department of Labor Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery

ACTION: Notice.

SUMMARY: On June 30, 2014, the Department of Labor (DOL) will submit the Office of the Assistant Secretary for Administration and Management (OASAM) sponsored information collection request (ICR) titled, ''Department of Labor Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery,'' to the Office of Management and Budget (OMB) for review and approval for continued use, without change, in accordance with the Paperwork Reduction Act of 1995 (PRA), 44 U.S.C. 3501 et seq. Public comments on the ICR are invited.

DATES: The OMB will consider all written comments that agency receives on or before July 30, 2014.

ADDRESSES: A copy of this ICR with applicable supporting documentation; including a description of the likely respondents, proposed frequency of response, and estimated total burden may be obtained free of charge from the RegInfo.gov Web site at *http://www.reginfo.gov/public/do/PRAMain* or by contacting Michel Smyth by telephone at 202–693–4129, TTY 202–693–8064, (these are not toll-free numbers) or by email at *DOL_PRA_PUBLIC@dol.gov.*

Submit comments about this request by mail or courier to the Office of Information and Regulatory Affairs, Attn: OMB Desk Officer for DOL–DM, Office of Management and Budget, Room 10235, 725 17th Street NW., Washington, DC 20503; by Fax: 202–395–6881 (this is not a toll-free number); or by email: *OIRA_submission@omb.eop.gov.* Commenters are encouraged, but not required, to send a courtesy copy of any comments by mail or courier to the U.S. Department of Labor-OASAM, Office of the Chief Information Officer, Attn: Departmental Information Compliance Management Program, Room N1301, 200 Constitution Avenue NW., Washington, DC 20210; or by email: *DOL_PRA_PUBLIC@dol.gov.*

FOR FURTHER INFORMATION CONTACT: Contact Michel Smyth by telephone at 202–693–4129, TTY 202–693–8064, (these are not toll-free numbers) or by email at *DOL_PRA_PUBLIC@dol.gov.*

Authority: 44 U.S.C. 3507(a)(1)(D).

SUPPLEMENTARY INFORMATION: This ICR seeks to extend PRA authority for the DOL Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery. The information collection activity will garner qualitative customer and stakeholder feedback in an efficient, timely manner, in accordance with the Administration's commitment to improving service delivery. By qualitative feedback we mean information that provides useful insights on perceptions and opinions, but are not statistical surveys that yield quantitative results that can be generalized to the population of study. This feedback will provide insights into customer or stakeholder perceptions, experiences, and expectations; provide an early warning of issues with service; or focus attention on areas where communication, training, or changes, in operations might improve delivery of products or services. These collections will allow for ongoing, collaborative, and actionable communications between the DOL and its customers and stakeholders. It will also allow feedback to contribute directly to the improvement of program management.

Feedback collected under this generic clearance will provide useful information, but it will not yield data that can be generalized to the overall population. This type of generic clearance for qualitative information will not be used for quantitative information collections that are designed to yield reliably actionable results, such as monitoring trends over time or documenting program performance. Such data uses require more rigorous designs that address: The target population to which generalizations will be made, the sampling frame, the sample design (including stratification and clustering), the precision requirements or power calculations that justify the proposed sample size, the expected response rate, methods for assessing potential non-response bias, the protocols for data collection, and any testing procedures that were or will be undertaken prior fielding the study. Depending on the degree of influence the results are likely to have, such collections may still be eligible for submission for other generic mechanisms that are designed to yield quantitative results.

This information collection is subject to the PRA. A Federal agency generally cannot conduct or sponsor a collection of information, and the public is generally not required to respond to an information collection, unless it is approved by the OMB under the PRA and displays a currently valid OMB Control Number. In addition, notwithstanding any other provisions of law, no person shall generally be subject to penalty for failing to comply with a collection of information that does not display a valid Control Number. *See* 5 CFR 1320.5(a) and 1320.6. The DOL obtains OMB approval for this information collection under Control Number 1225–0088.

OMB authorization for an ICR cannot be for more than three (3) years without renewal, and the current approval for this collection is scheduled to expire on June 30, 2014. The DOL seeks to extend PRA authorization for this information collection for three (3) more years, without any change to existing requirements. The DOL notes that existing information collection requirements submitted to the OMB receive a month-to-month extension while they undergo review. For additional substantive information about this ICR, see the related notice published in the **Federal Register** on March 28, 2014 (79 FR 17578).

Interested parties are encouraged to send comments to the OMB, Office of Information and Regulatory Affairs at the address shown in the **ADDRESSES** section by July 30, 2014. In order to help ensure appropriate consideration, comments should mention OMB Control

Number 1225–0088. The OMB is particularly interested in comments that:

- 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
- 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.

Agency: DOL–OASAM.

Title of Collection: Department of Labor Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery.

OMB Control Number: 1225–0088.

Affected Public: Individuals or Households; State, Local, and Tribal Governments; Private Sector—businesses or other for-profits, farms, and not-for-profit institutions.

Total Estimated Number of Respondents: 330,000.

Total Estimated Number of Responses: 330,000.

Total Estimated Annual Time Burden: 22,000 hours.

Total Estimated Annual Other Costs Burden: $0.

Dated: June 12, 2014.

Michel Smyth,

Departmental Clearance Officer.

[FR Doc. 2014–14260 Filed 6–17–14; 8:45 am]

BILLING CODE 4510–23–P

DEPARTMENT OF LABOR

Office of the Secretary

Bureau of International Labor Affairs; Labor Advisory Committee for Trade Negotiations and Trade Policy

ACTION: Meeting notice.

SUMMARY: Notice is hereby given of a meeting of the Labor Advisory Committee for Trade Negotiation and Trade Policy.

DATES: July 7, 2014 10:00 a.m. to 11:30 a.m.

ADDRESSES: U.S. Department of Labor, Secretary's Conference Room, 200 Constitution Ave. NW., Washington, DC.

FOR FURTHER INFORMATION CONTACT: Anne M. Zollner, Chief, Trade Policy and Negotiations Division; Phone: (202) 693–4890.

SUPPLEMENTARY INFORMATION:

Purpose: The meeting will include a review and discussion of current issues which influence U.S. trade policy. Potential U.S. negotiating objectives and bargaining positions in current and anticipated trade negotiations will be discussed. Pursuant to 19 U.S.C. 2155(f)(2)(A), it has been determined that the meeting will be concerned with matters the disclosure of which would seriously compromise the Government's negotiating objectives or bargaining positions. Therefore, the meeting is exempt from the requirements of subsections (a) and (b) of sections 10 and 11 of the Federal Advisory Committee Act (relating to open meetings, public notice, public participation, and public availability of documents). 5 U.S.C. app. Accordingly, the meeting will be closed to the public.

Signed at Washington, DC, the 12th day of June, 2014.

Carol Pier,

Deputy Undersecretary, International Affairs.

[FR Doc. 2014–14274 Filed 6–17–14; 8:45 am]

BILLING CODE 4510–28–P

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

[Notice 14–055]

Notice of Information Collection

AGENCY: National Aeronautics and Space Administration (NASA).

ACTION: Notice of information collection.

SUMMARY: The National Aeronautics and Space Administration, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on proposed and/or continuing information collections, as required by the Paperwork Reduction Act of 1995 (Pub. L. 104–13, 44 U.S.C. 3506(c)(2)(A)).

DATES: Consideration will be given to comments submitted within 30 calendar days from the date of this publication.

ADDRESSES: Interested persons are invited to submit written comments on the proposed information collection to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503, Attention: Desk Officer for NASA.

FOR FURTHER INFORMATION CONTACT: Requests for additional information or copies of the information collection instrument(s) and instructions should be directed to Frances Teel, NASA PRA Clearance Officer, NASA Headquarters, 300 E Street SW., Mail Code JF000, Washington, DC 20546, (202) 358–2225.

SUPPLEMENTARY INFORMATION:

I. Abstract

The National Aeronautics and Space Administration (NASA) Office of Diversity and Equal Opportunity and the Office of Procurement, in accordance with Title VI of the Civil Rights Act of 1964, Title IX of the Education Amendments of 1972, Section 504 of the Rehabilitation Act of 1973, and the Age Discrimination Act of 1975, requires grant awardees to submit an assurance of non-discrimination (NASA Form1206) as part of their initial grant application package. The requirement for assurance of non-discrimination compliance associated with federally assisted programs is long standing, derives from civil rights implementing regulations, and extends to the grant recipient's sub-grantees, contractors, successors, transferees, and assignees. Grant selectees are required to submit compliance information triennially when their award period exceeds 36 consecutive months. This information collection will also be used to enable NASA to conduct post-award civil rights compliance reviews.

II. Method of Collection

Electronic.

III. Data

Title: NASA Assurance of Civil Rights Compliance.

OMB Control Number: 2700–0148.

Type of review: Reinstatement of an existing information collection.

Affected Public: Business, or other for-profit, or not-for-profit.

Estimated Number of Respondents: 250.

Estimated Annual Responses: 1.

Estimated Time per Response: 4 hours.

Estimated Total Annual Burden Hours: 1000.

Estimated Total Annual Cost: $120.

IV. Request for Comments

Comments are invited on: (1) Whether the proposed collection of information is necessary for the proper performance of the functions of NASA, including whether the information collected has practical utility; (2) the accuracy of

NASA's estimate of the burden (including hours and cost) of the proposed collection of information; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) ways to minimize the burden of the collection of information on respondents, including automated collection techniques or the use of other forms of information technology.

Comments submitted in response to this notice will be summarized and included in the request to OMB for approval of this information collection. They will also become a matter of public record.

Frances Teel,

NASA PRA Clearance Officer.

[FR Doc. 2014–14211 Filed 6–17–14; 8:45 am]

BILLING CODE 7510–13–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 50–341; NRC–2014–0109]

DTE Electric Company; Fermi 2

AGENCY: Nuclear Regulatory Commission.

ACTION: License renewal application; opportunity to request a hearing and to petition for leave to intervene.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) is considering an application for the renewal of operating license number NPF–43, which authorizes DTE Electric Company, to operate Fermi 2. The renewed license would authorize the applicant to operate Fermi 2 for an additional 20 years beyond the period specified in the current license. The current operating license for Fermi 2 (NPF–43) expires at midnight on March 20, 2025. Fermi 2 is a boiling-water reactor designed by General Electric and is located near Frenchtown Township, Monroe County, Michigan.

DATES: A request for a hearing or petition for leave to intervene must be filed by August 18, 2014.

ADDRESSES: Please refer to Docket ID NRC–2014–0109 when contacting the NRC about the availability of information regarding this document. You may access publicly-available information related to this document using any of the following methods:

- *Federal Rulemaking Web site:* Go to *http://www.regulations.gov* and search for Docket ID NRC–2014–0109. Address questions about NRC dockets to Carol Gallagher; telephone: 301–287–3422; email: *Carol.Gallagher@nrc.gov.* For technical questions, contact the individual(s) listed in the **FOR FURTHER INFORMATION CONTACT** section of this document.
- *NRC's Agencywide Documents Access and Management System (ADAMS):* You may obtain publicly available documents online in the ADAMS Public Documents collection at *http://www.nrc.gov/reading-rm/adams.html.* To begin the search, select ''*ADAMS Public Documents*'' and then select ''*Begin Web-based ADAMS Search.*'' For problems with ADAMS, please contact the NRC's Public Document Room (PDR) reference staff at 1–800–397–4209, 301–415–4737, or by email to *pdr.resource@nrc.gov.* The ADAMS accession number for each document referenced in this document (if that document is available in ADAMS) is provided the first time that a document is referenced. The copy of the license renewal application is available in ADAMS under Accession Nos. ML14121A554 and ML14156A237.
- *NRC's PDR:* You may examine and purchase copies of public documents at the NRC's PDR, Room O1–F21, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852.

FOR FURTHER INFORMATION CONTACT: Daneira Meléndez-Colón, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; telephone: 301–415–3301, email: *Daneira.Melendez-Colon@nrc.gov.*

SUPPLEMENTARY INFORMATION:

I. Introduction

The NRC received a license renewal application (LRA) from DTE Electric Company, dated April 24, 2014, requesting renewal of operating license number NPF–43, which authorizes DTE Electric Company to operate Fermi 2 at 3486 megawatts thermal. Fermi 2 is located in Frenchtown Township, Monroe County, Michigan. DTE Electric Company submitted the application pursuant to part 54 of Title 10 of the *Code of Federal Regulations* (10 CFR). A notice of receipt of the LRA was published in the **Federal Register** on May 12, 2014 (79 FR 27003). On June 5, 2014, DTE Electric Company submitted an administrative amendment to the license renewal application. A copy of the amendment is available in ADAMS under Accession No. ML14156A237.

The NRC staff has determined that DTE Electric Company has submitted sufficient information in accordance with 10 CFR 2.101, 54.19, 54.21, 54.22, 54.23, 51.45, and 51.53(c), to enable the staff to undertake a review of the application, and that the application is therefore complete and acceptable for docketing. The current docket number, 50–341, for operating license number NPF–43, will be retained. The determination to accept the LRA for docketing does not constitute a determination that a renewed license should be issued, and does not preclude the NRC staff from requesting additional information as the review proceeds.

Before issuance of the requested renewed license, the NRC will have made the findings required by the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations. In accordance with 10 CFR 54.29, the NRC may issue a renewed license on the basis of its review if it finds that actions have been identified and have been or will be taken with respect to: (1) Managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified as requiring aging management review; and (2) time-limited aging analyses that have been identified as requiring review, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis (CLB) and that any changes made to the plant's CLB will comply with the Act and the Commission's regulations.

Additionally, in accordance with 10 CFR 51.95(c), the NRC will prepare an environmental impact statement for the renewal of the Fermi 2 operating license (NPF–43) as a supplement to the Commission's NUREG–1437, ''Generic Environmental Impact Statement for License Renewal of Nuclear Plants,'' dated June 2013. In considering the LRA, the Commission must find that the applicable requirements of Subpart A of 10 CFR Part 51 have been satisfied, and that matters raised under 10 CFR 2.335 have been addressed. Pursuant to 10 CFR 51.26, and as part of the environmental scoping process, the staff intends to hold public scoping meetings. Detailed information regarding the environmental scoping meetings will be the subject of a separate **Federal Register** notice.

II. Opportunity To Request a Hearing and Petition for Leave To Intervene

Within 60 days after the date of publication of this **Federal Register** notice, any person whose interest may be affected by this proceeding and who wishes to participate as a party in the proceeding must file a written request for a hearing or petition for leave to intervene with respect to the renewal of the license. Requests for a hearing or petitions for leave to intervene must 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, which is available at the NRC's PDR, located at One White Flint North, 11555 Rockville Pike (first floor), Rockville, Maryland 20852, and is accessible from the NRC Library on the Internet at *http://www.nrc.gov/reading-rm/adams.html.* Persons who do not have access to the Internet or who encounter problems in accessing the documents located in ADAMS should contact the NRC's PDR reference staff by telephone at 1–800–397–4209, or 301–415–4737, or by email at *PDR.Resource@nrc.gov.*

If a request for a hearing/petition for leave to intervene is filed within the 60-day period, the Commission or a presiding officer designated by the Commission or by the Chief Administrative Judge of the Atomic Safety and Licensing Board Panel will rule on the request and/or petition; and the Secretary of the Commission (Secretary) or the Chief Administrative Judge of the Atomic Safety and Licensing Board Panel will issue a notice of a hearing or an appropriate order. In the event that no request for a hearing or petition for leave to intervene is filed within the 60-day period, the NRC may, upon completion of its evaluations and upon making the findings required under 10 CFR parts 51 and 54, renew the license without further notice.

As required by 10 CFR 2.309, a request for hearing or petition for leave to intervene must set forth with particularity the interest of the petitioner in the proceeding, and how that interest may be affected by the results of the proceeding, taking into consideration the limited scope of matters that may be considered pursuant to 10 CFR parts 51 and 54. Pursuant to

10 CFR 2.309(d), the request for hearing or petition for leave to intervene must provide the name, address, and telephone number of the requestor or petitioner; and specifically explain the reasons why intervention should be permitted with particular reference to the following factors for the Fermi 2 site: (1) The nature of the requestor's/petitioner's right under the Act to be made a party to the proceeding; (2) the nature and extent of the requestor's/petitioner's property, financial, or other interest in the proceeding; and (3) the possible effect of any decision or order which may be entered in the proceeding on the requestor's/petitioner's interest. The request for hearing or petition for leave to intervene must also set forth the specific contentions which the requestor/petitioner seeks to have litigated at the proceeding.

In accordance with 10 CFR 2.309(f), each contention must consist of a specific statement of the issue of law or fact to be raised or controverted. In addition, the requestor/petitioner shall provide a brief explanation of the basis for each contention and a concise statement of the alleged facts or expert opinions which support the contention and on which the requestor/petitioner intends to rely at hearing. The requestor/petitioner must also provide references to those specific sources and documents on which the requestor/petitioner intends to rely to support its position on the issue. The requestor/petitioner must provide sufficient information to show that a genuine dispute exists with the applicant/licensee on a material issue of law or fact. This information must include references to specific portions of the application that the petitioner disputes and the supporting reasons for each dispute, or if the petitioner believes that the application fails to contain information on a relevant matter as required by law, the identification of each failure and the supporting reasons for the petitioner's belief. Contentions shall be limited to matters within the scope of the action under consideration. The contention must be one that, if proven, would entitle the requestor/petitioner to relief. A requestor/petitioner who fails to satisfy these requirements with respect to at least one contention will not be permitted to participate as a party.

Hearing requests, intervention petitions, and motions for leave to file new or amended contentions 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)–(iii).

A State, local governmental body, or Federally-recognized Indian tribe may submit a request for hearing or a petition to intervene to the Commission to participate as a party to the proceeding under 10 CFR 2.309(h)(1). The request for hearing or petition to intervene must contain at least one admissible contention, and must designate a single representative for the hearing. The request for hearing or petition to intervene should be submitted to the Commission by August 18, 2014. The request or petition must be filed in accordance with the filing instructions in the ''Electronic Submission (E-Filing)'' section of this document, and should meet the requirements for requests for hearing and petitions for leave to intervene set forth in this section, except that under 10 CFR 2.309(h)(2) a State, local governmental body, or Federally-recognized Indian tribe, does not need to address the standing requirements in 10 CFR 2.309(d) if the proceeding pertains to a production or utilization facility and that facility is located within its boundaries. A State, local governmental body, or Federally-recognized Indian tribe, may also have the opportunity to participate under 10 CFR 2.315(c).

If a hearing is granted, any person who does not wish, or is not qualified, to become a party to the proceeding may, in 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 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, within the limits and on the conditions fixed by the presiding officer. Such statements of position shall not be considered evidence in the proceeding. Persons desiring to make a limited appearance are requested to inform the Secretary of the Commission by August 18, 2014.

The Commission requests that each contention be given a separate numeric or alpha designation within one of the following groups: (1) Technical (primarily related to safety concerns); (2) environmental; or (3) miscellaneous.

As specified in 10 CFR 2.309, if two or more requestors/petitioners seek to co-sponsor a contention or propose substantially the same contention, the requestors/petitioners will be required to jointly designate a representative who shall have the authority to act for the requestors/petitioners with respect to that contention.

III. Electronic Submissions (E-Filing)

All documents filed in NRC adjudicatory proceedings, including a request for hearing, a petition for leave to intervene, any motion or other document filed in the proceeding prior to the submission of a request for hearing or petition for leave to intervene, and documents filed by interested governmental entities participating under 10 CFR 2.315(c), must be filed in accordance with the NRC's E-Filing rule (72 FR 49139; August 28, 2007). 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. Participants may not submit paper

copies of their filings unless they seek an exemption in accordance with the procedures described below.

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 request (1) A digital identification (ID) certificate, which allows the participant (or its counsel or representative) to digitally sign documents and access the E-Submittal server for any proceeding in which it is participating; and (2) advise the Secretary that the participant will be submitting a hearing request or petition for leave to intervene (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 hearing in this 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 Web site at *http://www.nrc.gov/site-help/e-submittals/getting-started.html.* System requirements for accessing the E-Submittal server are detailed in the NRC's ''Guidance for Electronic Submission,'' which is available on the agency's public Web site at *http://www.nrc.gov/site-help/e-submittals.html.* Participants may attempt to use other software not listed on the Web site, but should note that the NRC's E-Filing system does not support unlisted software, and the NRC Meta System Help Desk will not be able to offer assistance in using unlisted software.

If a participant is electronically submitting a document to the NRC in accordance with the E-Filing rule, the participant must file the document using the NRC's online, Web-based submission form. In order to serve documents through the Electronic Information Exchange System, users will be required to install a Web browser plug-in from the NRC's Web site. Further information on the Web-based submission form, including the installation of the Web browser plug-in, is available on the NRC's public Web site at *http://www.nrc.gov/site-help/e-submittals.html.*

Once a participant has obtained a digital ID certificate and a docket has been created, the participant can then submit a request for hearing or petition for leave to intervene. Submissions should be in Portable Document Format (PDF) in accordance with the NRC's guidance available on the NRC's public Web site at *http://www.nrc.gov/site-help/e-submittals.html.* A filing is considered complete at the time the documents are 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. Eastern Time on the due date. Upon receipt of a transmission, the E-Filing system time-stamps the document and sends the submitter an email notice confirming receipt of the document. The E-Filing system also distributes an email notice 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 documents on those participants separately. Therefore, applicants and other participants (or their counsel or representative) must apply for and receive a digital ID certificate before a hearing request/petition to intervene is filed so that they can obtain access to the document via the E-Filing system.

A person filing electronically using the NRC's adjudicatory E-Filing system may seek assistance by contacting the NRC Meta System Help Desk through the ''Contact Us'' link located on the NRC's public Web site at *http://www.nrc.gov/site-help/e-submittals.html,* by email to *MSHD.Resource@nrc.gov,* or by a toll-free call at 1–866–672–7640. The NRC Meta System Help Desk is available between 8 a.m. and 8 p.m., Eastern Time, Monday through Friday, excluding government holidays.

Participants who believe that they have a 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 requesting authorization to continue to submit documents in paper format. Such filings must be submitted by: (1) First class mail addressed to the Office of the Secretary of the Commission, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, Attention: Rulemaking and Adjudications Staff; or (2) courier, express mail, or expedited delivery service to the Office of the Secretary, Sixteenth Floor, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852, Attention: Rulemaking and Adjudications Staff. Participants filing a document in this manner are responsible for serving the document on all other participants. Filing is considered complete by first-class mail as of the time of deposit in the mail, or by courier, express mail, or expedited delivery service upon depositing the document with the provider of the service. A presiding officer, having granted an exemption request from using E-Filing, may require a participant or party to use E-Filing if the presiding officer subsequently determines that the reason for granting the exemption from use of E-Filing no longer exists.

Documents submitted in adjudicatory proceedings will appear in the NRC's electronic hearing docket which is available to the public at *http://ehd1.nrc.gov/ehd/,* unless excluded pursuant to an order of the Commission, or the presiding officer. Participants are requested not to include personal privacy information, such as social security numbers, home addresses, or home phone numbers in their filings, unless an NRC regulation or other law requires submission of such information. However, a request for hearing or petition for leave to intervene should include information on local residence in order to demonstrate a proximity assertion of interest in the proceeding. 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 are requested not to include copyrighted materials in their submission.

Detailed information about the license renewal process can be found under the Nuclear Reactors icon at *http://www.nrc.gov/reactors/operating/licensing/renewal.html* on the NRC's Web site. Copies of the application to renew the operating licenses for Fermi 2 are available for public inspection at the NRC's PDR, and at *http://www.nrc.gov/reactors/operating/licensing/renewal/applications.html,* the NRC's Web site, while the application is under review. The application may be accessed in ADAMS through the NRC Library on the Internet at *http://www.nrc.gov/reading-rm/adams.html* under ADAMS Accession Nos. ML14121A554 and ML14156A237. As stated above, persons who do not have access to ADAMS or who encounter problems in accessing the documents located in ADAMS may contact the NRC's PDR reference staff by telephone at 1–800–397–4209 or 301–415–4737, or by email to *pdr.resources@nrc.gov.*

The NRC staff has verified that a copy of the license renewal application is also available to local residents near Fermi 2 at the Ellis Library and Reference Center, 3700 South Custer Road, Monroe, MI 48161.

Dated at Rockville, Maryland, this 11th day of June 2014.

For the Nuclear Regulatory Commission.

John W. Lubinski,

Director, Division of License Renewal, Office of Nuclear Reactor Regulation.

[FR Doc. 2014–14272 Filed 6–17–14; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Advisory Committee on Reactor Safeguards (ACRS); Meeting of the ACRS Subcommittee on Plant Operations and Fire Protection; Notice of Meeting

The ACRS Subcommittee on Plant Operations and Fire Protection will hold a meeting on July 24, 2014, at the U.S. NRC Region III Office, 2443 Warrenville Road, Lisle, IL 60532–4352.

The meeting will be open to public attendance.

The agenda for the subject meeting shall be as follows:

Thursday, July 24, 2014—8:30 a.m. Until 12:00 p.m.

The Subcommittee will meet with Region III staff to discuss items of mutual interest. The Subcommittee will hear presentations by and hold discussions with representatives of the NRC staff and other interested persons regarding this matter. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the Full Committee.

Members of the public desiring to provide oral statements and/or written comments should notify the Designated Federal Official (DFO), Mark Banks (Telephone 301–415–3718 or Email: *Mark.Banks@nrc.gov*) five days prior to the meeting, if possible, so that appropriate arrangements can be made. Thirty-five hard copies of each presentation or handout should be provided to the DFO thirty minutes before the meeting. In addition, one electronic copy of each presentation should be emailed to the DFO one day before the meeting. If an electronic copy cannot be provided within this timeframe, presenters should provide the DFO with a CD containing each presentation at least thirty minutes before the meeting. Electronic recordings will be permitted only during those portions of the meeting that are open to the public. Detailed procedures for the conduct of and participation in ACRS meetings were published in the **Federal Register** on November 8, 2013 (78 CFR 67205–67206).

Detailed meeting agendas and meeting transcripts are available on the NRC Web site at *http://www.nrc.gov/reading-rm/doc-collections/acrs.* Information regarding topics to be discussed, changes to the agenda, whether the meeting has been canceled or rescheduled, and the time allotted to present oral statements can be obtained from the Web site cited above or by contacting the identified DFO. Moreover, in view of the possibility that the schedule for ACRS meetings may be adjusted by the Chairman as necessary to facilitate the conduct of the meeting, persons planning to attend should check with these references if such rescheduling would result in a major inconvenience.

Dated: June 11, 2014.

Cayetano Santos,

Chief, Technical Support Branch. Advisory Committee on Reactor Safeguards.

[FR Doc. 2014–14266 Filed 6–17–14; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Advisory Committee on Reactor Safeguards (ACRS); Meeting of the ACRS Subcommittee on Future Plant Designs; Notice of Meeting

The ACRS Subcommittee on Future Plant Designs will hold a meeting on July 8, 2014, Room T–2B1, 11545 Rockville Pike, Rockville, Maryland.

The entire meeting will be open to public attendance.

The agenda for the subject meeting shall be as follows:

Tuesday, July 8, 2014—8:30 a.m. until 12:30 p.m.

The Subcommittee will discuss additional results from several Design Acceptance Criteria (DAC) inspections completed for AP1000 Digital I&C and piping using the new inspection procedures. The Subcommittee will hear presentations by and hold discussions with the NRC staff and other interested persons regarding this matter. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the Full Committee.

Members of the public desiring to provide oral statements and/or written comments should notify the Designated Federal Official (DFO), Christina Antonescu (Telephone 301–415–6792 or Email: *Christina.Antonescu@nrc.gov*) five days prior to the meeting, if possible, so that appropriate arrangements can be made. Thirty-five hard copies of each presentation or handout should be provided to the DFO thirty minutes before the meeting. In addition, one electronic copy of each presentation should be emailed to the DFO one day before the meeting. If an electronic copy cannot be provided within this timeframe, presenters should provide the DFO with a CD containing each presentation at least thirty minutes before the meeting. Electronic recordings will be permitted only during those portions of the meeting that are open to the public. Detailed procedures for the conduct of and participation in ACRS meetings were published in the **Federal Register** on November 8, 2013 (78 CFR 67205–67206).

Detailed meeting agendas and meeting transcripts are available on the NRC Web site at *http://www.nrc.gov/reading-rm/doc-collections/acrs.* Information regarding topics to be discussed, changes to the agenda, whether the meeting has been canceled or rescheduled, and the time allotted to present oral statements can be obtained from the Web site cited above or by contacting the identified DFO. Moreover, in view of the possibility that the schedule for ACRS meetings may be adjusted by the Chairman as necessary to facilitate the conduct of the meeting, persons planning to attend should check with these references if such rescheduling would result in a major inconvenience.

If attending this meeting, please enter through the One White Flint North building, 11555 Rockville Pike, Rockville, MD. After registering with security, please contact Mr. Theron Brown (Telephone 240–888–9835) to be escorted to the meeting room.

Date: June 5, 2014.

Cayetano Santos,

Chief, Technical Support Branch, Advisory Committee on Reactor Safeguards.

[FR Doc. 2014–14269 Filed 6–17–14; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Advisory Committee on Reactor Safeguards (ACRS); Meeting of the ACRS Subcommittee on Economic Simplified Boiling Water Reactors (ESBWR); Notice of Meeting

The ACRS Subcommittee on ESBWR will hold a meeting on July 7, 2014, Room T–2B1, 11545 Rockville Pike, Rockville, Maryland.

The meeting will be open to public attendance with the exception of portions that may be closed to protect

information that is propriety pursuant to 5 U.S.C. 552(c)(4). The agenda for the subject meeting shall be as follows:

Monday, July 7, 2014—1:00 p.m. until 5:00 p.m.

The Subcommittee will review selected chapters of the NRC staff's Safety Evaluation Report regarding the Fermi, Unit 3, combined license application referencing the ESBWR design and the implementation of the lessons learned from the Fukushima accident. The Subcommittee will hear presentations by and hold discussions with representatives of the NRC staff, Detroit Edison, and other interested persons regarding this matter. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the Full Committee.

Members of the public desiring to provide oral statements and/or written comments should notify the Designated Federal Official (DFO), Christopher Brown (Telephone 301–415–7111 or Email: *Christopher.Brown@nrc.gov*) five days prior to the meeting, if possible, so that appropriate arrangements can be made. Thirty-five hard copies of each presentation or handout should be provided to the DFO thirty minutes before the meeting. In addition, one electronic copy of each presentation should be emailed to the DFO one day before the meeting. If an electronic copy cannot be provided within this timeframe, presenters should provide the DFO with a CD containing each presentation at least thirty minutes before the meeting. Electronic recordings will be permitted only during those portions of the meeting that are open to the public. Detailed procedures for the conduct of and participation in ACRS meetings were published in the **Federal Register** on November 8, 2013 (78 CFR 67205–67206).

Detailed meeting agendas and meeting transcripts are available on the NRC Web site at *http://www.nrc.gov/reading-rm/doc-collections/acrs*. Information regarding topics to be discussed, changes to the agenda, whether the meeting has been canceled or rescheduled, and the time allotted to present oral statements can be obtained from the Web site cited above or by contacting the identified DFO. Moreover, in view of the possibility that the schedule for ACRS meetings may be adjusted by the Chairman as necessary to facilitate the conduct of the meeting, persons planning to attend should check with these references if such rescheduling would result in a major inconvenience.

If attending this meeting, please enter through the One White Flint North building, 11555 Rockville Pike, Rockville, MD. After registering with security, please contact Mr. Theron Brown (240–888–9835) to be escorted to the meeting room.

Date: June 11, 2014.

Cayetano Santos,

Chief, Technical Support Branch, Advisory Committee on Reactor Safeguards.

[FR Doc. 2014–14270 Filed 6–17–14; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Advisory Committee on Reactor Safeguards (ACRS); Meeting of the ACRS Subcommittee on Planning and Procedures; Notice of Meeting

The ACRS Subcommittee on Planning and Procedures will hold a meeting on July 8, 2014, Room T–2B3, 11545 Rockville Pike, Rockville, Maryland.

The meeting will be open to public attendance with the exception of a portion that may be closed pursuant to 5 U.S.C. 552b(c)(2) and (6) to discuss organizational and personnel matters that relate solely to the internal personnel rules and practices of the ACRS, and information the release of which would constitute a clearly unwarranted invasion of personal privacy.

The agenda for the subject meeting shall be as follows:

Tuesday, July 8, 2014—12:30 p.m. Until 1:30 p.m.

The Subcommittee will discuss proposed ACRS activities and related matters. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the Full Committee.

Members of the public desiring to provide oral statements and/or written comments should notify the Designated Federal Official (DFO), Quynh Nguyen (Telephone 301–415–5844 or Email: *Quynh.Nguyen@nrc.gov*) five days prior to the meeting, if possible, so that arrangements can be made. Thirty-five hard copies of each presentation or handout should be provided to the DFO thirty minutes before the meeting. In addition, one electronic copy of each presentation should be emailed to the DFO one day before the meeting. If an electronic copy cannot be provided within this timeframe, presenters should provide the DFO with a CD containing each presentation at least thirty minutes before the meeting. Electronic recordings will be permitted only during those portions of the meeting that are open to the public. Detailed procedures for the conduct of and participation in ACRS meetings were published in the **Federal Register** on November 8, 2013, (78 CFR 67205–67206).

Information regarding changes to the agenda, whether the meeting has been canceled or rescheduled, and the time allotted to present oral statements can be obtained by contacting the identified DFO. Moreover, in view of the possibility that the schedule for ACRS meetings may be adjusted by the Chairman as necessary to facilitate the conduct of the meeting, persons planning to attend should check with the DFO if such rescheduling would result in a major inconvenience.

If attending this meeting, please enter through the One White Flint North building, 11555 Rockville Pike, Rockville, MD. After registering with security, please contact Mr. Theron Brown (240–888–9835) to be escorted to the meeting room.

Date: June 10, 2014.

Cayetano Santos,

Chief, Technical Support Branch, Advisory Committee on Reactor Safeguards.

[FR Doc. 2014–14268 Filed 6–17–14; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[NRC–2014–0143]

NRC Endorsement of Trial Use PRA Standards and Criteria for Evaluating Multi-Module Risk

AGENCY: Nuclear Regulatory Commission.

ACTION: Public meeting.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) plans to hold a public meeting to discuss NRC options regarding endorsement of ASME/ANS PRA standards and the staff proposed criteria for evaluating multi-module risk.

DATES: The public meeting will be held on June 26, 2014. See Section II, Public Meeting, of this document for more information on the meeting.

ADDRESSES: Please refer to Docket ID NRC–2014–0143 when contacting the NRC about the availability of information regarding this document. You may obtain publicly-available information related to this document using any of the following methods:

• *Federal Rulemaking Web site:* Go to *http://www.regulations.gov* and search for Docket ID NRC–2014–0143. Address questions about NRC dockets to Carol Gallagher; telephone: 301–287–3422; email: *Carol.Gallagher@nrc.gov.* For technical questions, contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section of this document.

• *NRC's Agencywide Documents Access and Management System (ADAMS):* You may obtain publicly-available documents online in the ADAMS Public Documents collection at *http://www.nrc.gov/reading-rm/adams.html.* To begin the search, select ''*ADAMS Public Documents*'' and then select ''*Begin Web-based ADAMS Search.''* For problems with ADAMS, please contact the NRC's Public Document Room (PDR) reference staff at 1–800–397–4209, 301–415–4737, or by email to *pdr.resource@nrc.gov.* The ADAMS accession number for each document referenced in this document (if that document is available in ADAMS) is provided the first time that a document is referenced.

• *NRC's PDR:* You may examine and purchase copies of public documents at the NRC's PDR, Room O1–F21, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852.

FOR FURTHER INFORMATION CONTACT: Mary Drouin, Office of Nuclear Regulatory Research, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; telephone: 301–251–7574; email: *Mary.Drouin@nrc.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

The ASME/ANS Joint Committee on Nuclear Risk Management (JCNRM) plans to publish three Probabilistic Risk Assessment (PRA) standards for trial use at the end of this calendar year or the beginning of 2015: (1) Low Power Shutdown PRA Standard, (2) Level 2 PRA Standard and (3) Advanced Light Water Reactor (ALWR) PRA standard. At a public meeting, the NRC seeks to discuss with interested stakeholders options for the NRC to endorse use of these standards.

The NRC has been discussing multi-unit risk for many years with limited discussion on multi-module risk. The NRC staff plans to discuss their expectations for Multi-Module risk in a public meeting and in a white paper entitled ''Multi-Module Risk–NRC Expectations'' (ADAMS Accession No. ML14150A330). The paper will be issued and available to the public by June 20, 2014.

II. Public Meeting

The public meeting will be held in Rockville, Maryland, at 21 Church Street in Room CSB 06B1 on June 26, 2014, at 8:00 a.m.

There will be two items on the agenda for the meeting. The first agenda item will be to discuss staff options for endorsement of the ASME/ANS standards to be issued for trial use and to solicit stakeholder input. The second agenda item will be discussion of the NRC white paper entitled ''Multi—Module Risk-NRC Expectations'' (ADAMS ML ML14150A330) which will be available to the public by June 20, 2014.

The purpose of these agenda items is for the NRC staff to answer questions, to provide clarification regarding the white paper, and to solicit early stakeholder comments on both of these subjects. This meeting will be a Category 2 public meeting.

Dated at Rockville, Maryland, this 11th day of June 2014.

For the Nuclear Regulatory Commission.

Richard P. Correia,

Director, Division of Risk Analysis, Office of Nuclear Regulatory Research.

[FR Doc. 2014–14271 Filed 6–17–14; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Meeting of the Advisory Committee on Reactor Safeguards Subcommittee on Fukushima

The Advisory Committee on Reactor Safeguards (ACRS) Subcommittee on Fukushima will hold a meeting on July 8, 2013, Room T–2B1, 11545 Rockville Pike, Rockville, Maryland.

The entire meeting will be open to public attendance.

The agenda for the subject meeting shall be as follows:

Tuesday, July 8, 2014—1:30 p.m. Until 5:00 p.m.

The Subcommittee will review and discuss NRC's Severe Accident Research activities. The Subcommittee will hear presentations by and hold discussions with the NRC staff and other interested persons regarding this matter. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the Full Committee.

Members of the public desiring to provide oral statements and/or written comments should notify the Designated Federal Official (DFO), Weidong Wang (Telephone 301–415–6279 or Email: *Weidong.Wang@nrc.gov*) five days prior to the meeting, if possible, so that appropriate arrangements can be made. Thirty-five hard copies of each presentation or handout should be provided to the DFO thirty minutes before the meeting. In addition, one electronic copy of each presentation should be emailed to the DFO one day before the meeting. If an electronic copy cannot be provided within this timeframe, presenters should provide the DFO with a CD containing each presentation at least thirty minutes before the meeting. Electronic recordings will be permitted only during those portions of the meeting that are open to the public. Detailed procedures for the conduct of and participation in ACRS meetings were published in the **Federal Register** on November 8, 2013 (78 CFR 67205–67206).

Detailed meeting agendas and meeting transcripts are available on the NRC Web site at *http://www.nrc.gov/reading-rm/doc-collections/acrs.* Information regarding topics to be discussed, changes to the agenda, whether the meeting has been canceled or rescheduled, and the time allotted to present oral statements can be obtained from the Web site cited above or by contacting the identified DFO. Moreover, in view of the possibility that the schedule for ACRS meetings may be adjusted by the Chairman as necessary to facilitate the conduct of the meeting, persons planning to attend should check with these references if such rescheduling would result in a major inconvenience.

If attending this meeting, please enter through the One White Flint North building, 11555 Rockville Pike, Rockville, MD. After registering with security, please contact Mr. Theron Brown (Telephone 240–888–9835) to be escorted to the meeting room.

Dated: June 11, 2014.

Cayetano Santos,

Chief Technical Support Branch Advisory Committee on Reactor Safeguards.

[FR Doc. 2014–14267 Filed 6–17–14; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[NRC–2014–0142]

Conducting the Section 106 Process of the National Historic Preservation Act for Uranium Recovery Licensing Actions

AGENCY: Nuclear Regulatory Commission.

ACTION: Draft interim staff guidance; request for comment.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) is issuing draft Interim Staff Guidance (ISG) FSME–ISG–02, ''Guidance for Conducting the Section 106 Process of the National Historic Preservation Act for Uranium Recovery Licensing Actions,'' for review and comment. The purpose of this draft ISG is to assist NRC staff in conducting the Section 106 process of the National Historic Preservation Act of 1966, as amended (NHPA), specific to uranium recovery licensing actions. While this guidance is primarily intended for the NRC staff, it also provides useful information to participants in the Section 106 process for uranium recovery licensing actions.

DATES: Submit comments by September 2, 2014. Comments received after this date will be considered if it is practical to do so, but the NRC is able to assure consideration only for comments received on or before this date.

ADDRESSES: You may submit comments by any of the following methods (unless this document describes a different method for submitting comments on a specific subject):

- *Federal Rulemaking Web site:* Go to *http://www.regulations.gov* and search for Docket ID NRC–2014–0142. Address questions about NRC dockets to Carol Gallagher; telephone: 301–287–3422; email: *Carol.Gallagher@nrc.gov*. For technical questions, contact the individuals listed in the **FOR FURTHER INFORMATION CONTACT** section of this document.
- *Mail comments to:* Cindy Bladey, Chief, Rules, Announcements, and Directives Branch, Office of Administration, Mail Stop: 3WFN–06–44M, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001.

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: Diana Diaz Toro, Office of Federal and State Materials and Environmental Management Programs, U.S. Nuclear Regulatory Commission, Washington DC 20555–0001; telephone: 301–415–0930; email: *Diana.Diaz-Toro@nrc.gov*.

SUPPLEMENTARY INFORMATION:

I. Obtaining Information and Submitting Comments

A. Obtaining Information

Please refer to Docket ID NRC–2014–0142 when contacting the NRC about the availability of information regarding this document. You may obtain publicly-available information related to this document by any of the following methods:

- *Federal Rulemaking Web site:* Go to *http://www.regulations.gov* and search for Docket ID NRC–2014–0142.
- *NRC's Agencywide Documents Access and Management System (ADAMS):* You may obtain publicly-available documents online in the ADAMS Public Documents collection at *http://www.nrc.gov/reading-rm/adams.html*. To begin the search, select ''*ADAMS Public Documents*'' and then select ''*Begin Web-based ADAMS Search*.'' For problems with ADAMS, please contact the NRC's Public Document Room (PDR) reference staff at 1–800–397–4209, 301–415–4737, or by email to *pdr.resource@nrc.gov*. The draft ISG, FSME–ISG–02, ''Guidance for Conducting the Section 106 Process of the National Historic Preservation Act for Uranium Recovery Licensing Actions,'' is available in ADAMS under accession number ML14163A049.
- *NRC's PDR:* You may examine and purchase copies of public documents at the NRC's PDR, Room O1–F21, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852.

B. Submitting Comments

Please include Docket ID NRC–2014–0142 in the subject line of your comment submission, in order to ensure that the NRC is able to make your comment submission available to the public in this docket.

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 *http://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 submissions into ADAMS.

II. Background

The NRC is responsible for regulating the civilian use of nuclear materials and facilities in a manner that protects public health and safety from radiological hazards and common defense and security. The NRC has statutory authority to regulate and license uranium recovery facilities through the Atomic Energy Act of 1954, as amended (AEA) and the Uranium Mill Tailings Radiation Control Act of 1978. In part, these statutes require that the NRC to ensure the management of source material, as defined in AEA Section 11z., and byproduct material, as defined in AEA Section 11e.(2), conforms to applicable regulatory requirements.

License applicants initiate the proposed federal action by submitting an application to the NRC for projects or activities requiring an NRC license or approval. The NRC must then make a decision whether to grant or deny the applicant's request. In addition to the NRC staff's safety review, the NRC staff conducts an environmental review, as required under the National Environmental Policy Act of 1969, as amended (NEPA). Through the environmental review, the NRC evaluates the potential environmental impacts from the applicant's proposal. The NRC's NEPA implementing regulations are in Part 51 of Title 10 of the *Code of Federal Regulations* (10 CFR), ''Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions.''

Congress enacted the NHPA to support and encourage the preservation of prehistoric and historic resources. Section 106 of the NHPA requires federal agencies to take into account the effects of their undertakings on historic properties and allow the Advisory Council on Historic Preservation an opportunity to review and comment on the undertaking. The NHPA implementing regulations are in 36 CFR part 800, ''Protection of Historic Properties.'' Federal agencies carry out the Section 106 process through consultation as appropriate with the State Historic Preservation Officer, Tribal Historic Preservation Officer, other federal, state, and local governmental agencies, Tribal governments, other interested parties, and the public. The NRC conducts the Section 106 process as part of its reviews of requests for license applications. In accordance with 36 CFR 800.1(c), the NRC must complete the

Section 106 process prior to making licensing decision on the request for the licensing action.

The NRC's guidance for conducting environmental reviews in support of the Office of Federal and State Materials and Environmental Management Programs and Office of Nuclear Material Safety and Safeguards licensing and regulatory actions is provided in NUREG–1748, ''Environmental Review Guidance for Licensing Actions Associated With Nuclear Material Safety and Safeguards Programs'' (ADAMS Accession No. ML032450279). NUREG–1748 also includes general guidance for complying with the NHPA Section 106 process.

Over the past several years, an increase in the number of licensing action for *in situ* uranium recovery (ISR) facilities has resulted in an increase in the NRC's Section 106 activities. In addition, the complexity of the Section 106 reviews associated with the ISR licensing actions has grown significantly. As a result, the NRC has decided to supplement the Section 106 guidance contained in NUREG–1748 by providing specific guidance for the NRC's implementation of the Section 106 process in uranium recovery licensing actions. The purpose of this draft ISG is to assist NRC staff in conducting the Section 106 process specific to uranium recovery licensing actions. While this guidance is primarily intended for the NRC staff, it is also provides useful information for participants in the Section 106 process for uranium recovery licensing actions. This ISG, however, only provides guidance and does not impose regulatory requirements.

The NRC staff plans to revise the applicable sections of NUREG–1748 to include the guidance in this ISG. Until then, the NRC staff will use this ISG and revise and update the document as needed to clarify the content or incorporate subsequent modifications.

The NRC staff will review and consider the comments received in response to this request and revise the ISG as appropriate.

Dated at Rockville, Maryland, this 12th day of June 2014.

For the U.S. Nuclear Regulatory Commission.

Aby Mohseni,

Deputy Director, Environmental Protection and Performance Assessment Directorate, Division of Waste Management and Environmental Protection, Office of Federal and State Materials and Environmental Management Programs.

[FR Doc. 2014–14276 Filed 6–17–14; 8:45 am]

BILLING CODE 7590–01–P

SECURITIES AND EXCHANGE COMMISSION

[Investment Company Act Release No. 31079; 812–14274]

Absolute Shares Trust, et al.; Notice of Application

June 12, 2014.

AGENCY: Securities and Exchange Commission (''Commission'').

ACTION: Notice of an application for an order under section 12(d)(1)(J) of the Investment Company Act of 1940 (the ''1940 Act'') for exemptions from sections 12(d)(1)(A), (B), and (C) of the 1940 Act, under sections 6(c) and 17(b) of the 1940 Act for an exemption from section 17(a) of the 1940 Act, and under section 6(c) of the 1940 Act for an exemption from rule 12d1–2(a) under the 1940 Act.

SUMMARY: *Summary of the Application:* Applicants request an order that would (a) permit certain registered open-end management investment companies that operate as ''funds of funds'' to acquire shares of certain registered open-end management investment companies, registered closed-end management investment companies, business development companies as defined by section 2(a)(48) of the 1940 Act (''business development companies''), and registered unit investment trusts that are within or outside the same group of investment companies as the acquiring investment companies and (b) permit certain registered open-end management investment companies relying on rule 12d1–2 under the 1940 Act to invest in certain financial instruments.

APPLICANTS: Absolute Shares Trust (''Trust''), Millington Securities, Inc. (''Advisor'') and Foreside Fund Services, LLC (the ''Distributor'').

DATES: *Filing Dates:* The application was filed February 6, 2014, and amended on May 7, 2014, May 30, 2014, and June 5, 2014.

HEARING OR NOTIFICATION OF HEARING: An order granting the application will be issued unless the Commission orders a hearing. Interested persons may request a hearing by writing to the Commission's Secretary and serving applicants with a copy of the request, personally or by mail. Hearing requests should be received by the Commission by 5:30 p.m. on July 7, 2014, and should be accompanied by proof of service on applicants, in the form of an affidavit or, for lawyers, a certificate of service. Hearing requests should state the nature of the writer's interest, the reason for the request, and the issues contested. Persons who wish to be notified of a hearing may request notification by writing to the Commission's Secretary.

ADDRESSES: Secretary, U.S. Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090. Applicants: Absolute Shares Trust, c/o Don Schreiber, Jr., 331 Newman Springs Road, Suite 122, Red Bank, NJ 07701; Millington Securities, Inc., c/o Don Schreiber, Jr., 331 Newman Springs Road, Suite 122, Red Bank, NJ 07701; Foreside Fund Services LLC, Three Canal Plaza, Suite 100, Portland, ME 04101.

FOR FURTHER INFORMATION CONTACT: Anil K. Abraham, Senior Special Counsel, at (202) 551–2614, or Daniele Marchesani, Branch Chief, at (202) 551–6821 (Division of Investment Management, Chief Counsel's Office).

SUPPLEMENTARY INFORMATION: The following is a summary of the application. The complete application may be obtained via the Commission's Web site by searching for the file number, or for an applicant using the ''Company'' name box, at *http://www.sec.gov/search/search.htm* or by calling (202) 551–8090.

Applicants' Representations

1. Absolute Shares Trust is an open-end management company registered under the 1940 Act and organized as a Delaware statutory trust. The Trust has multiple series (''Funds''), which pursue distinct investment objectives and strategies.[1]

2. Millington Securities, Inc., a Delaware limited liability company, is a registered investment adviser under the Investment Advisers Act of 1940 (the ''Advisers Act''). Millington Securities, Inc., or an entity controlling, controlled by, or under common control with Millington Securities, Inc., serves, or will serve, as the investment adviser to each of the Funds.[2] The Advisor may

[1] The Applicants request that the order apply not only to any existing series of the Trusts, but that the order also extend to any future series of the Trusts, and any other existing or future registered open-end management investment companies and any series thereof that are part of the same group of investment companies, as defined in Section 12(d)(1)(G)(ii) of the 1940 Act, as the Trusts and are, or may in the future be, advised by Millington Securities, Inc. or any other investment adviser controlling, controlled by, or under common control with Millington Securities, Inc. (together with the existing series of the Trusts, each series a ''Fund,'' and collectively, the ''Funds''). All entities that currently intend to rely on the requested order are named as applicants. Any other entity that relies on the order in the future will comply with the terms and conditions of the application.

[2] All references to the term ''Millington Securities, Inc.'' include any successors in interest to Millington Securities, Inc. A successor is limited to an entity that results from a reorganization into

enter into sub-advisory agreements with one or more additional investment advisers to act as ''Sub-Advisers'' with respect to particular Funds (each, a ''Sub-Adviser''). The Distributor is a Broker (as defined below) and serves as the existing Funds' principal underwriter and distributor.

3. Applicants request relief to the extent necessary to permit: (a) Each Fund (each, a ''Fund of Funds,'' and collectively, the ''Funds of Funds'') to acquire shares of registered open-end management investment companies (each an ''Unaffiliated Open-End Investment Company''), registered closed-end management investment companies, business development companies (each registered closed-end management investment company and each business development company, an ''Unaffiliated Closed-End Investment Company'' and, together with the Unaffiliated Open-End Investment Companies, the ''Unaffiliated Investment Companies''), and registered unit investment trusts (''UITs'') (the ''Unaffiliated Trusts,'' collectively with the Unaffiliated Investment Companies, the ''Unaffiliated Funds''), in each case, that are not part of the same ''group of investment companies'' as the Funds of Funds; [3] (b) the Unaffiliated Funds, their principal underwriters and any broker or dealer registered under the Securities Exchange Act of 1934 (the ''1934 Act'') (''Broker'') to sell shares of such Unaffiliated Funds to the Funds of Funds; (c) the Funds of Funds to acquire shares of other registered investment companies, including open-end management investment companies and series thereof, closed-end management investment companies and UITs, as well as business development companies (if any), in the same group of investment companies as the Funds of Funds (collectively, the ''Affiliated Funds,'' and, together with the Unaffiliated Funds, the ''Underlying Funds''); [4] and (d) the Affiliated Funds, their principal underwriters and any Broker to sell shares of the Affiliated Funds to the Funds of Funds.[5] Applicants also request an order under sections 6(c) and 17(b) of the 1940 Act to exempt applicants from section 17(a) to the extent necessary to permit Underlying Funds organized as open-end investment companies (''Underlying Open-End Funds'') and UITs (''Underlying UITs'') to sell their shares to Funds of Funds and redeem their shares from Funds of Funds.

4. Applicants also request an exemption under section 6(c) from rule 12d1–2 under the 1940 Act to permit any existing or future Fund of Funds that relies on section 12(d)(1)(G) of the 1940 Act (''Section 12(d)(1)(G) Fund of Funds'') and that otherwise complies with rule 12d1–2 under the 1940 Act, to also invest, to the extent consistent with its investment objective(s), policies, strategies and limitations, in other financial instruments that may not be securities within the meaning of section 2(a)(36) of the 1940 Act (''Other Investments'').

Applicants' Legal Analysis

A. Section 12(d)(1)

1. Section 12(d)(1)(A) of the 1940 Act, in relevant part, prohibits a registered investment company from acquiring shares of an investment company if the securities represent more than 3% of the total outstanding voting stock of the acquired company, more than 5% of the total assets of the acquiring company, or, together with the securities of any other investment companies, more than 10% of the total assets of the acquiring company. Section 12(d)(1)(B) of the 1940 Act prohibits a registered open-end investment company, its principal underwriter, and any Broker from selling the investment company's shares to another investment company if the sale will cause the acquiring company to own more than 3% of the acquired company's voting stock, or if the sale will cause more than 10% of the acquired company's voting stock to be owned by investment companies generally. Section 12(d)(1)(C) prohibits an investment company from acquiring any security issued by a registered closed-end investment company if such acquisition would result in the acquiring company, any other investment companies having the same investment adviser, and companies controlled by such investment companies, collectively, owning more than 10% of the outstanding voting stock of the registered closed-end investment company.

2. Section 12(d)(1)(J) of the 1940 Act provides that the Commission may exempt any person, security, or transaction, or any class or classes of persons, securities or transactions, from any provision of section 12(d)(1) if the exemption is consistent with the public interest and the protection of investors. Applicants request an exemption under section 12(d)(1)(J) of the 1940 Act from the limitations of sections 12(d)(1)(A), (B) and (C) to the extent necessary to permit: (i) The Funds of Funds to acquire shares of Underlying Funds in excess of the limits set forth in section 12(d)(1)(A) and (C) of the 1940 Act; and (ii) the Underlying Funds, their principal underwriters and any Broker to sell shares of the Underlying Funds to the Funds of Funds in excess of the limits set forth in section 12(d)(1)(B) of the 1940 Act.

3. Applicants state that the proposed arrangement will not give rise to the policy concerns underlying sections 12(d)(1)(A), (B), and (C), which include concerns about undue influence by a fund of funds over underlying funds, excessive layering of fees, and overly complex fund structures. Accordingly, applicants believe that the requested exemption is consistent with the public interest and the protection of investors.

4. Applicants submit that the proposed structure will not result in the exercise of undue influence by a Fund of Funds or its affiliated persons over the Underlying Funds. Applicants assert that the concern about undue influence does not arise in connection with a Fund of Funds' investment in the Affiliated Funds because they are part of the same group of investment companies. To limit the control a Fund of Funds or Fund of Funds Affiliate [6] may have over an Unaffiliated Fund,

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another jurisdiction or a change in the type of business organization.

[3] For purposes of the request for relief, the term ''group of investment companies'' means any two or more registered investment companies, including closed-end investment companies, that hold themselves out to investors as related companies for purposes of investment and investor services.

[4] Certain of the Underlying Funds may be registered under the 1940 Act as either UITs or open-end management investment companies and have obtained exemptions from the Commission necessary to permit their shares to be listed and traded on a national securities exchange at negotiated prices and, accordingly, to operate as exchange-traded funds (collectively, ''ETFs'' and each, an ''ETF''). In addition, certain of the Underlying Funds may in the future pursue their investment objectives through a master-feeder arrangement in reliance on section 12(d)(1)(E) of the 1940 Act. In accordance with condition 12, a Fund of Funds may not invest in an Underlying Fund that operates as a feeder fund unless the feeder fund is part of the same ''group of investment companies'' as its corresponding master fund or the Fund of Funds. If a Fund of Funds invests in an Affiliated Fund that operates as a feeder fund and the corresponding master fund is not within the same ''group of investment companies'' as the Fund of Funds and Affiliated Fund, the master fund would be an Unaffiliated Fund for purposes of the application and its conditions.

[5] Applicants state that they do not believe that investments in business development companies present any particular considerations or concerns that may be different from those presented by investments in registered closed-end investment companies.

[6] A ''Fund of Funds Affiliate'' is the Advisor, any Sub-Adviser, promoter or principal underwriter of a Fund of Funds, as well as any person controlling, controlled by or under common control with any of those entities. An ''Unaffiliated Fund Affiliate'' is an investment adviser(s), sponsor, promoter or principal underwriter of any Unaffiliated Fund or any person controlling, controlled by or under common control with any of those entities.

applicants propose a condition prohibiting the Advisor and any person controlling, controlled by or under common control with the Advisor, and any investment company and any issuer that would be an investment company but for section 3(c)(1) or section 3(c)(7) of the 1940 Act advised or sponsored by the Advisor or any person controlling, controlled by or under common control with the Advisor (collectively, the ''Group'') from controlling (individually or in the aggregate) an Unaffiliated Fund within the meaning of section 2(a)(9) of the 1940 Act. The same prohibition would apply to any Sub-Adviser and any person controlling, controlled by or under common control with the Sub-Adviser, and any investment company or issuer that would be an investment company but for section 3(c)(1) or 3(c)(7) of the 1940 Act (or portion of such investment company or issuer) advised or sponsored by the Sub-Adviser or any person controlling, controlled by or under common control with the Sub-Adviser (collectively, the ''Sub-Adviser Group'').

5. With respect to closed-end Underlying Funds, applicants note that although closed-end funds may not be unduly influenced by a holder's right of redemption, closed-end Underlying Funds may be unduly influenced by a holder's ability to vote a large block of stock. To address this concern, applicants submit that, with respect to a Fund's investment in an Unaffiliated Closed-End Investment Company, (i) each member of the Group or Sub-Adviser Group that is an investment company or an issuer that would be an investment company but for section 3(c)(1) or 3(c)(7) of the 1940 Act will vote its shares of the Unaffiliated Closed-End Investment Company in the manner prescribed by section 12(d)(1)(E) of the 1940 Act and (ii) each other member of the Group or Sub-Adviser Group will vote its shares of the Unaffiliated Closed-End Investment Company in the same proportion as the vote of all other holders of the same type of such Unaffiliated Closed-End Investment Company's shares. Applicants state that, in this way, an Unaffiliated Closed-End Investment Company will be protected from undue influence by a Fund of Funds through the voting of the Unaffiliated Closed-End Investment Company's shares.

6. Applicants propose other conditions to limit the potential for undue influence over the Unaffiliated Funds, including that no Fund of Funds or Fund of Funds Affiliate (except to the extent it is acting in its capacity as an investment adviser to an Unaffiliated Investment Company or sponsor to an Unaffiliated Trust) will cause an Unaffiliated Fund to purchase a security in an offering of securities during the existence of any underwriting or selling syndicate of which a principal underwriter is an Underwriting Affiliate (''Affiliated Underwriting'').[7]

7. To further ensure that an Unaffiliated Investment Company understands the implications of a Fund of Funds' investment under the requested exemptive relief, prior to its investment in the shares of an Unaffiliated Investment Company in excess of the limit of section 12(d)(1)(A)(i) of the 1940 Act, a Fund of Funds and the Unaffiliated Investment Company will execute an agreement stating, without limitation, that each of their boards of directors or trustees (for any entity, the ''Board'') and their investment advisers understand the terms and conditions of the order and agree to fulfill their responsibilities under the order (the ''Participation Agreement''). Applicants note that an Unaffiliated Investment Company (including an ETF or an Unaffiliated Closed-End Investment Company) would also retain its right to reject any initial investment by a Fund of Funds in excess of the limits in section 12(d)(1)(A)(i) of the 1940 Act by declining to execute the Participation Agreement with the Fund of Funds. In addition, an Unaffiliated Investment Company (other than an ETF or closed-end fund whose shares are purchased by a Fund of Funds in the secondary market) will retain its right at all times to reject any investment by a Fund of Funds. Finally, subject solely to the giving of notice to a Fund of Funds and the passage of a reasonable notice period, an Unaffiliated Fund (including an ETF or an Unaffiliated Closed-End Investment Company) could terminate a Participation Agreement with the Fund of Funds.

8. Applicants state that they do not believe that the proposed arrangement will result in excessive layering of fees. The Board of each Fund of Funds, including a majority of the trustees who are not ''interested persons'' within the meaning of section 2(a)(19) of the 1940 Act (the ''Independent Trustees''), will find that the management or advisory fees charged under a Fund of Funds' advisory contract are based on services provided that are in addition to, rather than duplicative of, services provided under the advisory contract(s) of any Underlying Fund in which the Fund of Funds may invest. In addition, the Advisor will waive fees otherwise payable to it by a Fund of Funds in an amount at least equal to any compensation (including fees received pursuant to any plan adopted by an Unaffiliated Investment Company under rule 12b–1 under the 1940 Act) received from an Unaffiliated Fund by the Advisor, or an affiliated person of the Advisor, other than any advisory fees paid to the Advisor or an affiliated person of the Advisor by the Unaffiliated Investment Company, in connection with the investment by the Fund of Funds in the Unaffiliated Fund.

9. Applicants further state that any sales charges and/or service fees charged with respect to shares of a Fund of Funds will not exceed the limits applicable to funds of funds set forth in in rule 2830 of the Conduct Rules of the NASD (''NASD Conduct Rule 2830'').[8]

10. Applicants submit that the proposed arrangement will not create an overly complex fund structure. Applicants note that no Underlying Fund will acquire securities of any other investment company or company relying on section 3(c)(1) or 3(c)(7) of the 1940 Act in excess of the limits contained in section 12(d)(1)(A) of the 1940 Act, except in certain circumstances identified in condition 12 below.

B. Section 17(a)

1. Section 17(a) of the 1940 Act generally prohibits sales or purchases of securities between a registered investment company and any affiliated person of the company. Section 2(a)(3) of the 1940 Act defines an ''affiliated person'' of another person to include (a) any person directly or indirectly owning, controlling, or holding with power to vote, 5% or more of the outstanding voting securities of the other person; (b) any person 5% or more of whose outstanding voting securities are directly or indirectly owned, controlled, or held with power to vote by the other person; and (c) any person directly or indirectly controlling, controlled by, or under common control with the other person.

2. Applicants state that the Funds of Funds and the Affiliated Funds may be deemed to be under the common control of the Advisor and, therefore, affiliated

[7] An ''Underwriting Affiliate'' is a principal underwriter in any underwriting or selling syndicate that is an officer, director, trustee, advisory board member, investment adviser, sub-adviser or employee of the Fund of Funds, or a person of which any such officer, director, trustee, investment adviser, sub-adviser, member of an advisory board or employee is an affiliated person. An Underwriting Affiliate does not include any person whose relationship to an Unaffiliated Fund is covered by section 10(f) of the 1940 Act.

[8] Any references to NASD Conduct Rule 2830 include any successor or replacement FINRA rule to NASD Conduct Rule 2830.

persons of one another. Applicants also state that the Funds of Funds and the Underlying Open-End Funds and Underlying UITs may also be deemed to be affiliated persons of one another if a Fund of Funds owns 5% or more of the outstanding voting securities of one or more of such Underlying Open-End Funds or Underlying UITs. Applicants state that the sale of shares by the Underlying Open-End Funds or Underlying UITs to the Funds of Funds and the purchase of those shares from the Funds of Funds by the Underlying Open-End Funds or Underlying UITs (through redemptions) could be deemed to violate section 17(a).[9]

3. Section 17(b) of the 1940 Act authorizes the Commission to grant an order permitting a transaction otherwise prohibited by section 17(a) if it finds that (i) the terms of the proposed transaction are fair and reasonable and do not involve overreaching on the part of any person concerned; (ii) the proposed transaction is consistent with the policies of each registered investment company concerned; and (iii) the proposed transaction is consistent with the general purposes of the 1940 Act. Section 6(c) of the 1940 Act permits the Commission to exempt any person or transactions from any provision of the 1940 Act if such exemption is necessary or appropriate in the public interest and consistent with the protection of investors and the purposes fairly intended by the policy and provisions of the 1940 Act.

4. Applicants submit that the proposed transactions satisfy the standards for relief under sections 17(b) and 6(c) of the 1940 Act. Applicants state that the terms of the transactions are reasonable and fair and do not involve overreaching. Applicants state that the terms upon which an Underlying Open-End Fund will sell its shares to or purchase its shares from a Fund of Funds will be in accordance with the rules and regulations under the 1940 Act.[10] Applicants also state that the proposed transactions will be consistent with the policies of each Fund of Funds and any Underlying Fund, and with the general purposes of the 1940 Act.

C. Other Investments by Section 12(d)(1)(G) Funds of Funds

1. Section 12(d)(1)(G) of the 1940 Act provides that section 12(d)(1) will not apply to securities of an acquired company purchased by an acquiring company if: (i) The acquiring company and acquired company are part of the same ''group of investment companies,'' as defined in section 12(d)(1)(G)(ii) of the 1940 Act; (ii) the acquiring company holds only securities of acquired companies that are part of the same ''group of investment companies,'' as defined in section 12(d)(1)(G)(ii) of the 1940 Act, government securities, and short-term paper; (iii) the aggregate sales loads and distribution-related fees of the acquiring company and the acquired company are not excessive under rules adopted pursuant to section 22(b) or section 22(c) of the 1940 Act by a securities association registered under section 15A of the 1934 Act or by the Commission; and (iv) the acquired company has a policy that prohibits it from acquiring securities of registered open-end management investment companies or registered UITs in reliance on section 12(d)(1)(F) or (G) of the 1940 Act.

2. Rule 12d1–2 under the 1940 Act permits a registered open-end investment company or a registered UIT that relies on section 12(d)(1)(G) of the 1940 Act to acquire, in addition to securities issued by another registered investment company in the same group of investment companies, government securities, and short-term paper: (1) Securities issued by an investment company that is not in the same group of investment companies, when the acquisition is in reliance on section 12(d)(1)(A) or 12(d)(1)(F) of the 1940 Act; (2) securities (other than securities issued by an investment company); and (3) securities issued by a money market fund, when the investment is in reliance on rule 12d1–1 under the 1940 Act. For the purposes of rule 12d1–2, ''securities'' means any security as defined in section 2(a)(36) of the 1940 Act.

3. Applicants state that the proposed arrangement would comply with rule 12d1–2 under the 1940 Act, but for the fact that the Section 12(d)(1)(G) Funds of Funds may invest a portion of their assets in Other Investments. Applicants request an order under section 6(c) of the 1940 Act for an exemption from rule 12d1–2(a) to allow the Section 12(d)(1)(G) Funds of Funds to invest in Other Investments. Applicants assert that permitting a Section 12(d)(1)(G) Fund of Funds to invest in Other Investments as described in the application would not raise any of the concerns that section 12(d)(1) of the 1940 Act was intended to address.

4. Consistent with its fiduciary obligations under the 1940 Act, a Section 12(d)(1)(G) Fund of Funds' Board will review the advisory fees charged by the Section 12(d)(1)(G) Fund of Funds' investment adviser(s) to ensure that the fees are based on services provided that are in addition to, rather than duplicative of, services provided pursuant to the advisory agreement of any investment company in which the Section 12(d)(1)(G) Fund of Funds may invest.

Applicants' Conditions

A. Investments by Funds of Funds in Underlying Funds

Applicants agree that the order granting the requested relief to permit Funds of Funds to invest in Underlying Funds shall be subject to the following conditions:

1. The members of the Group will not control (individually or in the aggregate) an Unaffiliated Fund within the meaning of section 2(a)(9) of the 1940 Act. The members of a Sub-Adviser Group will not control (individually or in the aggregate) an Unaffiliated Fund within the meaning of section 2(a)(9) of the 1940 Act. With respect to a Fund's investment in an Unaffiliated Closed-End Investment Company, (i) each member of the Group or Sub-Adviser Group that is an investment company or an issuer that would be an investment company but for section 3(c)(1) or 3(c)(7) of the 1940 Act will vote its shares of the Unaffiliated Closed-End Investment Company in the manner prescribed by section 12(d)(1)(E) of the 1940 Act and (ii) each other member of the Group or Sub-Adviser Group will vote its shares of the Unaffiliated Closed-End Investment Company in the same proportion as the vote of all other holders of the same type of such Unaffiliated Closed-End Investment Company's shares. If, as a result of a

[9] Applicants acknowledge that receipt of any compensation by (a) an affiliated person of a Fund of Funds, or an affiliated person of such person, for the purchase by the Fund of Funds of shares of an Underlying Fund or (b) an affiliated person of an Underlying Fund, or an affiliated person of such person, for the sale by the Underlying Fund of its shares to a Fund of Funds may be prohibited by section 17(e) (1) of the 1940 Act. The Participation Agreement also will include this acknowledgement.

[10] Applicants note that a Fund of Funds generally would purchase and sell shares of an Underlying Fund that operates as an ETF or a closed-end fund through secondary market transactions rather than through principal transactions with the Underlying Fund. Applicants nevertheless request relief from sections 17(a)(1) and (2) to permit each Fund of Funds that is an affiliated person, or an affiliated person of an affiliated person, as defined in section 2(a)(3) of the 1940 Act, of an ETF or a closed-end fund to purchase or redeem shares from the ETF or closed-end fund. Applicants are not seeking relief from section 17(a) for, and the requested relief will not apply to, transactions where an ETF or a closed-end fund could be deemed an affiliated person, or an affiliated person of an affiliated person, of a Fund of Funds because an investment adviser to the ETF or an entity controlling, controlled by or under common control with the investment adviser to the ETF or closed-end fund is also an investment adviser to the Fund of Funds.

decrease in the outstanding voting securities of any other Unaffiliated Fund, the Group or a Sub-Adviser Group, each in the aggregate, becomes a holder of more than 25 percent of the outstanding voting securities of such Unaffiliated Fund, then the Group or the Sub-Adviser Group will vote its shares of the Unaffiliated Fund in the same proportion as the vote of all other holders of the Unaffiliated Fund's shares. This condition will not apply to a Sub-Adviser Group with respect to an Unaffiliated Fund for which the Sub-Adviser or a person controlling, controlled by, or under common control with the Sub-Adviser acts as the investment adviser within the meaning of section 2(a)(20)(A) of the 1940 Act (in the case of an Unaffiliated Investment Company) or as the sponsor (in the case of an Unaffiliated Trust).

2. No Fund of Funds or Fund of Funds Affiliate will cause any existing or potential investment by the Fund of Funds in an Unaffiliated Fund to influence the terms of any services or transactions between the Fund of Funds or a Fund of Funds Affiliate and the Unaffiliated Fund or an Unaffiliated Fund Affiliate.

3. The Board of each Fund of Funds, including a majority of the Independent Trustees, will adopt procedures reasonably designed to ensure that its Advisor and any Sub-Adviser to the Fund of Funds are conducting the investment program of the Fund of Funds without taking into account any consideration received by the Fund of Funds or Fund of Funds Affiliate from an Unaffiliated Fund or an Unaffiliated Fund Affiliate in connection with any services or transactions.

4. Once an investment by a Fund of Funds in the securities of an Unaffiliated Investment Company exceeds the limit of section 12(d)(1)(A)(i) of the 1940 Act, the Board of the Unaffiliated Investment Company, including a majority of the Independent Trustees, will determine that any consideration paid by the Unaffiliated Investment Company to a Fund of Funds or a Fund of Funds Affiliate in connection with any services or transactions: (a) Is fair and reasonable in relation to the nature and quality of the services and benefits received by the Unaffiliated Investment Company; (b) is within the range of consideration that the Unaffiliated Investment Company would be required to pay to another unaffiliated entity in connection with the same services or transactions; and (c) does not involve overreaching on the part of any person concerned. This condition does not apply with respect to any services or transactions between an Unaffiliated Investment Company and its investment adviser(s), or any person controlling, controlled by, or under common control with such investment adviser(s).

5. No Fund of Funds or Fund of Funds Affiliate (except to the extent it is acting in its capacity as an investment adviser to an Unaffiliated Investment Company or sponsor to an Unaffiliated Trust) will cause an Unaffiliated Fund to purchase a security in any Affiliated Underwriting.

6. The Board of an Unaffiliated Investment Company, including a majority of the Independent Trustees, will adopt procedures reasonably designed to monitor any purchases of securities by the Unaffiliated Investment Company in an Affiliated Underwriting once an investment by a Fund of Funds in the securities of the Unaffiliated Investment Company exceeds the limit of section 12(d)(1)(A)(i) of the 1940 Act, including any purchases made directly from an Underwriting Affiliate. The Board of the Unaffiliated Investment Company will review these purchases periodically, but no less frequently than annually, to determine whether the purchases were influenced by the investment by the Fund of Funds in the Unaffiliated Investment Company. The Board of the Unaffiliated Investment Company will consider, among other things: (a) Whether the purchases were consistent with the investment objectives and policies of the Unaffiliated Investment Company; (b) how the performance of securities purchased in an Affiliated Underwriting compares to the performance of comparable securities purchased during a comparable period of time in underwritings other than Affiliated Underwritings or to a benchmark such as a comparable market index; and (c) whether the amount of securities purchased by the Unaffiliated Investment Company in Affiliated Underwritings and the amount purchased directly from an Underwriting Affiliate have changed significantly from prior years. The Board of the Unaffiliated Investment Company will take any appropriate actions based on its review, including, if appropriate, the institution of procedures designed to ensure that purchases of securities in Affiliated Underwritings are in the best interest of shareholders.

7. Each Unaffiliated Investment Company will maintain and preserve permanently, in an easily accessible place, a written copy of the procedures described in the preceding condition, and any modifications to such procedures, and will maintain and preserve for a period of not less than six years from the end of the fiscal year in which any purchase in an Affiliated Underwriting occurred, the first two years in an easily accessible place, a written record of each purchase of securities in an Affiliated Underwriting once an investment by a Fund of Funds in the securities of an Unaffiliated Investment Company exceeds the limit of section 12(d)(1)(A)(i) of the 1940 Act, setting forth (1) the party from whom the securities were acquired, (2) the identity of the underwriting syndicate's members, (3) the terms of the purchase, and (4) the information or materials upon which the determinations of the Board of the Unaffiliated Investment Company were made.

8. Prior to its investment in shares of an Unaffiliated Investment Company in excess of the limit set forth in section 12(d)(1)(A)(i) of the 1940 Act, the Fund of Funds and the Unaffiliated Investment Company will execute a Participation Agreement stating, without limitation, that their Boards and their investment advisers understand the terms and conditions of the order and agree to fulfill their responsibilities under the order. At the time of its investment in shares of an Unaffiliated Investment Company in excess of the limit set forth in section 12(d)(1)(A)(i), a Fund of Funds will notify the Unaffiliated Investment Company of the investment. At such time, the Fund of Funds will also transmit to the Unaffiliated Investment Company a list of the names of each Fund of Funds Affiliate and Underwriting Affiliate. The Fund of Funds will notify the Unaffiliated Investment Company of any changes to the list as soon as reasonably practicable after a change occurs. The Unaffiliated Investment Company and the Fund of Funds will maintain and preserve a copy of the order, the Participation Agreement, and the list with any updated information for the duration of the investment and for a period of not less than six years thereafter, the first two years in an easily accessible place.

9. Before approving any advisory contract under section 15 of the 1940 Act, the Board of each Fund of Funds, including a majority of the Independent Trustees, shall find that the advisory fees charged under the advisory contract are based on services provided that are in addition to, rather than duplicative of, services provided under the advisory contract(s) of any Underlying Fund in which the Fund of Funds may invest. Such finding, and the basis upon which the finding was made, will be recorded fully in the minute books of the appropriate Fund of Funds.

10. The Advisor will waive fees otherwise payable to it by a Fund of Funds in an amount at least equal to any compensation (including fees received pursuant to any plan adopted by an Unaffiliated Investment Company pursuant to rule 12b–1 under the 1940 Act) received from an Unaffiliated Fund by the Advisor, or an affiliated person of the Advisor, other than any advisory fees paid to the Advisor or its affiliated person by the Unaffiliated Investment Company, in connection with the investment by the Fund of Funds in the Unaffiliated Fund. Any Sub-Adviser will waive fees otherwise payable to the Sub-Adviser, directly or indirectly, by the Fund of Funds in an amount at least equal to any compensation received by the Sub-Adviser, or an affiliated person of the Sub-Adviser, from an Unaffiliated Fund, other than any advisory fees paid to the Sub-Adviser or its affiliated person by the Unaffiliated Investment Company, in connection with the investment by the Fund of Funds in the Unaffiliated Fund made at the direction of the Sub-Adviser. In the event that the Sub-Adviser waives fees, the benefit of the waiver will be passed through to the Fund of Funds.

11. Any sales charges and/or service fees charged with respect to shares of a Fund of Funds will not exceed the limits applicable to funds of funds set forth in NASD Conduct Rule 2830.

12. No Underlying Fund will acquire securities of any other investment company or company relying on section 3(c)(1) or 3(c)(7) of the 1940 Act, in excess of the limits contained in section 12(d)(1)(A) of the 1940 Act, except to the extent that such Underlying Fund: (a) Acquires such securities in compliance with section 12(d)(1)(E) of the 1940 Act and is either an Affiliated Fund or is in the same ''group of investment companies'' as its corresponding master fund; (b) receives securities of another investment company as a dividend or as a result of a plan of reorganization of a company (other than a plan devised for the purpose of evading section 12(d)(1) of the 1940 Act); or (c) acquires (or is deemed to have acquired) securities of another investment company pursuant to exemptive relief from the Commission permitting such Underlying Fund to: (i) Acquire securities of one or more investment companies for short-term cash management purposes or (ii) engage in inter-fund borrowing and lending transactions.

B. Other Investments by Section 12(d)(1)(G) Funds of Funds

In addition, Applicants agree that the order granting the requested relief to permit Section 12(d)(1)(G) Funds of Funds to invest in Other Investments shall be subject to the following condition:

1. Applicants will comply with all provisions of rule 12d1–2 under the 1940 Act, except for paragraph (a)(2) to the extent that it restricts any Section 12(d)(1)(G) Fund of Funds from investing in Other Investments as described in the application.

For the Commission, by the Division of Investment Management, pursuant to delegated authority.

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–14203 Filed 6–17–14; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. IC–31080; File No. 812–14120]

WhiteHorse Finance, Inc., et al.; Notice of Application

June 12, 2014.

AGENCY: Securities and Exchange Commission (''Commission'').

ACTION: Notice of application for an order under section 57(i) of the Investment Company Act of 1940 (the ''Act'') and rule 17d-1 under the Act to permit certain joint transactions otherwise prohibited by section 57(a)(4) of the Act and rule 17d-1 under the Act.

SUMMARY: *Summary of Application:* Applicants request an order to permit a business development company (''BDC'') to co-invest with certain affiliated investment funds in portfolio companies.

Applicants: WhiteHorse Finance, Inc. (the ''Company''), WhiteHorse Finance Warehouse, LLC (''WhiteHorse Warehouse''), H.I.G. Bayside Debt & LBO Fund II, L.P., H.I.G. Bayside Loan Opportunity Fund II, L.P., H.I.G. Bayside Loan Opportunity Fund III (Europe-Euro), L.P., H.I.G. Bayside Loan Opportunity Fund III (Europe-US$), L.P., WhiteHorse VI, Ltd., WhiteHorse VII, Ltd. and WhiteHorse VIII, Ltd. (collectively with H.I.G. Bayside Debt & LBO Fund II, L.P., H.I.G. Bayside Loan Opportunity Fund II, L.P., H.I.G. Bayside Loan Opportunity Fund III (Europe-Euro), L.P. and H.I.G. Bayside Loan Opportunity Fund III (Europe-US$), L.P., the ''Existing Private Funds''), H.I.G. WhiteHorse Advisers, LLC (the ''Company Adviser''), Bayside Capital, Inc. and H.I.G. WhiteHorse Capital, LLC (each, a ''Current Adviser to Private Funds'' and, collectively, the ''Current Advisers to Private Funds'' and, together with the Company Adviser, each, an ''Adviser'' and, together, the ''Advisers'') and H.I.G. Capital, L.L.C. (collectively, the ''Applicants'').

DATES: *Filing Dates:* The application was filed on February 5, 2013 and amended on July 3, 2013, October 15, 2013 and May 21, 2014.

Hearing or Notification of Hearing: An order granting the requested relief will be issued unless the Commission orders a hearing. Interested persons may request a hearing by writing to the Commission's Secretary and serving applicants with a copy of the request, personally or by mail. Hearing requests should be received by the Commission by 5:30 p.m. on July 7, 2014, and should be accompanied by proof of service on applicants, in the form of an affidavit or, for lawyers, a certificate of service. Hearing requests should state the nature of the writer's interest, the reason for the request, and the issues contested. Persons who wish to be notified of a hearing may request notification by writing to the Commission's Secretary.

ADDRESSES: Secretary, U.S. Securities and Exchange Commission, 100 F St. NE., Washington, DC 20549–1090. Applicants: c/o Richard Siegel, Esq., H.I.G. WhiteHorse Advisers, LLC, 1450 Brickell Avenue, 31st Floor, Miami, FL 33131.

FOR FURTHER INFORMATION CONTACT: Emerson S. Davis, Senior Counsel, at (202) 551–6868, or Daniele Marchesani, Branch Chief, at (202) 551–6821 (Division of Investment Management, Chief Counsel's Office).

SUPPLEMENTARY INFORMATION: The following is a summary of the application. The complete application may be obtained via the Commission's Web site by searching for the file number, or for an applicant using the Company name box, at *http://www.sec.gov/search/search.htm* or by calling (202) 551–8090.

Applicants' Representations

1. The Company is an externally managed, non-diversified, closed-end management investment company that has elected to be regulated as a BDC under the Act.[1] The Company's

[1] Section 2(a)(48) defines a BDC to be any closed-end investment company that operates for the purpose of making investments in securities described in sections 55(a)(1) through 55(a)(3) of the Act and makes available significant managerial

Continued

objectives is to generate current income and capital appreciation by primarily investing in private, small-capitalization companies (generally in the range of $10 million to $50 million) through first liens loans, second liens loans, senior debt securities, mezzanine loans or equity interests. The Company's board of directors currently consists of five members (the ''Board''), three of whom are not ''interested persons'' of the Company within the meaning of section 2(a)(19) of the Act (the ''Independent Directors'').

2. The Company Adviser, a Delaware limited liability company, is registered under the Investment Advisers Act of 1940 (''Advisers Act'') and is the Company's investment adviser. H.I.G Capital, L.L.C. is an alternative investment and asset management firm and is registered under the Advisers Act. WhiteHorse Capital, LLC serves as the investment adviser for WhiteHorse VI, Ltd., WhiteHorse VII, Ltd. and WhiteHorse VIII. Ltd in its capacity as the collateral manager to each of those three entities.

3. The Existing Private Funds are entities formed under the laws of Delaware or under the laws of the Cayman Islands. In reliance on the exclusion from the definition of ''Investment Company'' provided by section 3(c)(7) of the Act, none of the Existing Private Funds will be registered under the Act. Each Existing Private Fund is managed by the Current Advisers to Private Funds in accordance with an investment advisory agreement (collectively, the ''Advisory Agreements''). The Company expects that any portfolio company that is an appropriate investment for a Private Fund [2] may also be an appropriate investment for the Company, with certain exceptions based on available capital or diversification.

4. Applicants seek an order (''Order'') [3] to allow the Company, on the one hand, and one or more Private Funds that may be prohibited from co-investing with the Company by reason of section 57 of the Act, on the other hand, to co-invest in the same issuers of securities. For purposes of the application, a ''Co-Investment Transaction'' means any transaction in which the Company (or one of its Wholly-Owned Investment Subsidiaries) participated together with a Private Fund in reliance on the requested Order. ''Potential Co-Investment Transaction'' means any investment opportunity in which the Company (or a Wholly-Owned Investment Subsidiary) could not participate together with one or more Private Funds without obtaining and relying on the Order.

5. The Company may, from time to time, form a special purpose subsidiary (a ''Wholly-Owned Investment Subsidiary'').[4] Wholly-Owned Investment Subsidiaries would be prohibited from investing in a Co-Investment Transaction with any Private Fund because the Wholly-Owned Investment Subsidiary would be a company controlled by the Company for purposes of section 57(a)(4) and rule 17d–1. Applicants request that any Wholly-Owned Investment Subsidiary be permitted to participate in Co-Investment Transactions in lieu of the Company and that any Wholly-Owned Investment Subsidiary's participation in any such transaction be treated, for purposes of the Order, as though the Company were participating directly. Applicants represent that this treatment is justified because any Wholly-Owned Investment Subsidiary would have no purpose other than serving as a holding vehicle for the Company's investments or debt and, therefore, no conflicts of interest could arise between the Company and any Wholly-Owned Investment Subsidiary. The Board would make all relevant determinations under the conditions with regard to a Wholly-Owned Investment Subsidiary's participation in a Co-Investment Transaction, and the Board would be informed of, and take into consideration, any proposed use of any Wholly-Owned Investment Subsidiary in the Company's place. If the Company proposes to participate in the same Co-Investment Transaction with any of its Wholly-Owned Investment Subsidiaries, the Board will also be informed of, and take into consideration, the relative participation of the Company and any Wholly-Owned Investment Subsidiary. WhiteHorse Warehouse is a Wholly-Owned Investment Subsidiary of the Company formed for the special purpose of providing liquidity support through a credit facility.

6. Applicants represent that the Current Advisers to Private Funds will refer to the Company Adviser all Potential Co-Investment Transactions within the Company's Objectives and Strategies [5] that are considered for a Private Fund, and such investment opportunities may result in a Co-Investment Transaction. For each such referral, the Company Adviser will consider only the investment objective, investment policies, investment position, investment strategies, investment restrictions, regulatory and tax requirements, capital available for investment and other pertinent factors applicable to the Company. Likewise, when selecting investments for a Private Fund, the Adviser to the Private Fund will select investments separately for the Private Fund, considering only the investment objective, investment policies, investment position, investment strategies, investment restrictions, regulatory and tax requirements, capital available for investment and other pertinent factors applicable to such Private Fund. Each Co-Investment Transaction and the proposed allocation of such Co-Investment Transaction would be approved prior to the actual investment by the required majority (within the meaning of section 57(o) of the Act) of the Board (the ''Required Majority'').

7. Other than pro rata dispositions and Follow-On Investments [6] as

assistance with respect to the issuers of such securities.

[2] ''Private Fund'' means any Existing Private Fund or any entity (i) whose investment adviser is an Adviser, (b) that would be an investment company but for section 3(c)(1) or 3(c)(7) of the Act, and (c) that intends to participate in the Co-Investment Program. ''Adviser'' means (a) the Company Adviser, (b) the Current Advisers to Private Funds and (c) any future investment adviser that controls, or is controlled by or is under common control with any of the Company Adviser or the Current Advisers to Private Funds and is registered as an investment adviser under the Adviser Act.

[3] All existing entities that currently intend to rely on the Order have been named as Applicants and any entities that may rely on the Order in the future will comply with the terms and conditions of the application.

[4] The term ''Wholly-Owned Investment Subsidiary'' means an entity (a) whose sole business purpose is to hold one or more investments and issue debt on behalf of the Company, to obtain debt financing for those investments and, in the case of a Wholly-Owned Investment Subsidiary organized as a small business investment company under the Small Business Investment Act of 1958 (''SBA Act''), maintain a license under the SBA Act and issue debentures guaranteed by the Small Business Administration; (b) that is wholly-owned by the Company (with the Company at all times directly or indirectly holding, beneficially and of record, 100% of the voting and economic interests); (c) with respect to which the Board has the sole authority to make all determinations with respect to the Wholly-Owned Investment Subsidiary's participation under the conditions of the application; and (d) that is an entity that would be an investment company but for section 3(c)(1) or 3(c)(7) of the Act.

[5] ''Objectives and Strategies'' means the Company's investment objectives and strategies, as described in its registration statement on Form N–2 and other filings made with the Commission by the Company under the Securities Act of 1933 Act, as amended (''1933 Act''), any reports filed by the Company with the Commission under the Securities Exchange Act of 1934, as amended, and the Company's reports to stockholders.

[6] ''Follow-On Investment'' means any additional investment in an existing portfolio company, including through the exercise of warrants, conversion privileges or other rights to acquire securities of the portfolio company.

provided in conditions 7 and 8, and after making the determinations required in conditions 1 and 2(a), the Company Adviser will present each Potential Co-Investment Transaction and the proposed allocation to the directors of the Board eligible to vote under section 57(o) of the Act (''Eligible Directors''), and the Required Majority will approve each Co-Investment Transaction prior to any investment by the Company.

8. With respect to the pro rata dispositions and Follow-On Investments provided in conditions 7 and 8, the Company may participate in a pro rata disposition or Follow-On Investment without obtaining prior approval of the Required Majority if, among other things: (i) The proposed participation of the Company and each Private Fund in such disposition or Follow-On-Investment is proportionate to its outstanding investments in the issuer immediately preceding the disposition or Follow-On Investment, as the case may be; and (ii) the Board has approved the Company's participation in pro rata dispositions or Follow-On Investments as being in the best interests of the Company. If the Board does not so approve, any such disposition or Follow-On Investment will be submitted to the Company's Eligible Directors. The Board of the Company may at any time rescind, suspend or qualify its approval of pro rata dispositions and Follow-On Investments with the result that all dispositions and/or Follow-On Investments must be submitted to the Eligible Directors.

9. No Independent Director will have any direct or indirect financial interest in any Co-Investment Transaction or any interest in any portfolio company, other than through an interest (if any) in the securities of the Company.

Applicants' Legal Analysis

1. Section 57(a)(4) of the Act prohibits certain affiliated persons of a BDC from participating in a joint transaction with the BDC in contravention of rules as prescribed by the Commission. Section 57(i) of the Act provides that, until the Commission prescribes rules under section 57(a)(4), the Commission's rules under section 17(d) of the Act applicable to registered closed-end investment companies will be deemed to apply to BDCs. Because the Commission has not adopted any rules under section 57(a)(4), rule 17d–1 applies to BDCs. The Company Adviser and any Private Fund that it advises could be deemed to be persons related to the Company in a manner described by section 57(b) and therefore prohibited by section 57(a)(4) and rule 17d–1 from participating in the Co-Investment Program. In addition, because the other Advisers are ''affiliated persons'' of the Company Adviser, such Advisers and Private Funds advised by any of them could be deemed to be persons related to the Company in a manner described by section 57(b) and also prohibited from participating in the Co-Investment Program. Finally, because WhiteHorse Warehouse and any other Wholly-Owned Investment Subsidiary are controlled by the Company, they are subject to section 57(a)(4), and thus also subject to the provisions of rule 17d–1.

2. Rule 17d–1, as made applicable to BDCs by section 57(i), prohibits any person who is related to a BDC in a manner described in section 57(b), acting as principal, from participating in, or effecting any transaction in connection with, any joint enterprise or other joint arrangement or profit-sharing plan in which the BDC is a participant, absent an order from the Commission. In passing upon applications under rule 17d–1, the Commission considers whether the company's participation in the joint transaction is consistent with the provisions, policies, and purposes of the Act and the extent to which such participation is on a basis different from or less advantageous than that of other participants.

3. Applicants state that they expect that co-investment in portfolio companies by the Company and the Private Funds will increase favorable investment opportunities for the Company and the Private funds.

4. Applicants submit that the Required Majority will approve each Co-Investment Transaction before investment, and other protective conditions set forth in the application, will ensure that the Company will be treated fairly. Applicants state that the Company's participation in the Co-Investment Transactions will be consistent with the provisions, policies, and purposes of the Act and on a basis that is not different from or less advantageous than that of other participants.

Applicants' Conditions

Applicants agree that any order granting the requested relief will be subject to the following conditions:

1. Each time an investment adviser considers a Potential Co-Investment Transaction for a Private Fund that falls within the Company's then-current Objectives and Strategies, the Company Adviser will make an independent determination of the appropriateness of such investment for the Company in light of the Company's then-current circumstances.

2. (a) If the Company Adviser deems the Company's participation in any Potential Co-Investment Transaction to be appropriate for the Company, it will then determine an appropriate level of investment for the Company;

(b) If the aggregate amount recommended by the Company Adviser to be invested in such Potential Co-Investment Transaction by the Company, together with the amount proposed to be invested by the Private Funds, collectively, in the same transaction, exceeds the amount of the investment opportunity, then the investment opportunity will be allocated among them pro rata based on each such party's capital available for investment in the asset class being allocated, up to the amount proposed to be invested by each party. The Company Adviser will provide the Eligible Directors with information concerning the Private Funds' available capital to assist the Eligible Directors with their review of the Company's investments for compliance with these allocation procedures; and

(c) After making the determinations required in conditions 1 and 2(a), the Company Adviser will then distribute written information concerning the Potential Co-Investment Transaction, including the amount proposed to be invested by the Company and any Private Fund, to the Eligible Directors for their consideration. The Company will co-invest with the Private Funds only if, prior to participating in such Co-Investment Transaction, the Required Majority concludes that:

(i) The terms of the transaction, including the consideration to be paid, are reasonable and fair to the Company and its stockholders and do not involve overreaching in respect of the Company or its stockholders on the part of any person concerned;

(ii) the transaction is consistent with:

(A) the interests of the stockholders of the Company; and

(B) the Company's then-current Objectives and Strategies;

(iii) the investment by the Private Funds would not disadvantage the Company, and participation by the Company would not be on a basis different from, or less advantageous than, that of the Private Funds; provided, that if any of the Private Funds, but not the Company itself, gains the right to nominate a director for election to a portfolio company's board of directors or the right to have a board observer or any similar right to participate in the governance or management of the portfolio company,

such event will not be interpreted to prohibit the Required Majority from reaching the conclusions required by this condition (2)(c)(iii), if:

(A) The Eligible Directors will have the right to ratify the selection of such director or board observer, if any;

(B) the Advisers agree to, and do, provide periodic reports to the Company's Board with respect to the actions of the director or the information received by the board observer or obtained through the exercise of any similar right to participate in the governance or management of the portfolio company; and

(C) any fees or other compensation that any Private Fund or any affiliated person of any Private Fund receives in connection with the right of the Private Funds to nominate a director or appoint a board observer or otherwise to participate in the governance or management of the portfolio company will be shared proportionately among the participating Private Funds (which may, in turn, share their portion with their affiliated persons) and the Company in accordance with the amount of each party's investment; and

(iv) the proposed investment by the Company will not benefit the Advisers or the Private Funds, or any affiliated person of any of them (other than the parties to the Co-Investment Transaction), except (a) to the extent permitted by condition 13; (b) to the extent permitted by sections 17(e) or 57(k) of the Act as applicable; (c) indirectly, as a result of an interest in the securities issued by one of the parties to the Co-Investment Transaction; or (d) in the case of fees or other compensation described in condition 2(c)(iii)(C).

3. The Company has the right to decline to participate in any Potential Co-Investment Transaction or to invest less than the amount proposed.

4. The Company Adviser will present to the Board, on a quarterly basis, a record of all investments in Potential Co-Investment Transactions made by the Private Funds during the preceding quarter that fell within the Company's then-current Objectives and Strategies that were not made available to the Company and an explanation of why the investment opportunities were not offered to the Company. All information presented to the Board pursuant to this condition will be kept for the life of the Company and at least two years thereafter, and will be subject to examination by the Commission and its Staff.

5. Except for Follow-On Investments made in accordance with condition 8, the Company will not invest in reliance on the Order in any issuer in which any Private Fund or any affiliated person of the Private Funds is an existing investor.

6. The Company will not participate in any Potential Co-Investment Transaction unless the terms, conditions, price, class of securities to be purchased, settlement date and registration rights will be the same for the Company as for each participating Private Fund. The grant to a Private Fund, but not the Company, of the right to nominate a director for election to a portfolio company's board of directors, the right to have an observer on the board of directors or similar rights to participate in the governance or management of the portfolio company will not be interpreted so as to violate this condition 6, if conditions 2(c)(iii)(A), (B) and (C) are met.

7. (a) If any Private Fund elects to sell, exchange or otherwise dispose of an interest in a security that was acquired in a Co-Investment Transaction, the Company Adviser will:

(i) Notify the Company of the proposed disposition at the earliest practical time; and

(ii) formulate a recommendation as to participation by the Company in any such disposition.

(b) The Company will have the right to participate in such disposition on a proportionate basis at the same price and on the same terms and conditions as those applicable to the participating Private Funds.

(c) The Company may participate in such disposition without obtaining prior approval of the Required Majority if: (i) The proposed participation of the Company and of each Private Fund in such disposition is proportionate to its outstanding investment in the issuer immediately preceding the disposition; (ii) the Board has approved as being in the best interests of the Company the ability to participate in such dispositions on a pro rata basis (as described in greater detail in this application); and (iii) the Board is provided on a quarterly basis with a list of all dispositions made in accordance with this condition. In all other cases, the Company Adviser will provide its written recommendation as to the Company's participation to the Eligible Directors, and the Company will participate in such disposition solely to the extent that a Required Majority determines that it is in the Company's best interests.

(d) The Company and each participating Private Fund shall each bear its own expenses in connection with any such disposition.

8. (a) If any Private Fund desires to make a Follow-On Investment in a portfolio company whose securities were acquired in a Co-Investment Transaction, the Company Adviser will:

(i) Notify the Company of the proposed transaction at the earliest practical time; and

(ii) formulate a recommendation as to the proposed participation, including the amount of the proposed Follow-On investment, by the Company.

(b) The Company may participate in such Follow-On Investment without obtaining prior approval of the Required Majority if: (i) The proposed participation of the Company and each Private Fund in such investment is proportionate to its outstanding investment in the issuer immediately preceding the Follow-On Investment; and (ii) the Board has approved as being in the best interests of the Company the ability to participate in Follow-On Investments on a pro rata basis (as described in greater detail in this application). In all other cases, the Company Adviser will provide its written recommendation as to the Company's participation to the Eligible Directors, and the Company will participate in such Follow-On Investment solely to the extent that a Required Majority determines that it is in the Company's best interests.

(c) If with respect to any Follow-On Investment:

(i) The amount of the opportunity is not based on the Company's and the Private Funds' outstanding investments immediately preceding the Follow-On Investment; and

(ii) the aggregate amount recommended by the Company Adviser to be invested by the Company in the Follow-On Investment, together with the amount proposed to be invested by the participating Private Funds in the same transaction, exceeds the amount of the opportunity, then the amount invested by each such party will be allocated among them pro rata based on the ratio of capital available for investment in the asset class being allocated of each party, up to the amount proposed to be invested by each.

(d) The acquisition of Follow-On Investments as permitted by this condition will be considered a Co-Investment Transaction for all purposes and be subject to the other conditions set forth in this application.

9. The Independent Directors will be provided quarterly for review all information concerning Potential Co-Investment Transactions and Co-Investment Transactions, including investments made by the Private Funds

that the Company considered but declined to participate in, so that the Independent Directors may determine whether all investments made during the preceding quarter, including those investments which the Company considered but declined to participate in, comply with the conditions of the Order. In addition, the Independent Directors will consider at least annually the continued appropriateness for the Company of participating in new and existing Co-Investment Transactions.

10. The Company will maintain the records required by section 57(f)(3) of the Act as if each of the investments permitted under these conditions were approved by the Required Majority under section 57(f) of the Act.

11. No Independent Directors will also be a director, general partner, managing member or principal, or otherwise an ''affiliated person'' (as defined in the Act) of any Private Fund.

12. The expenses, if any, associated with acquiring, holding or disposing of any securities acquired in a Co-Investment Transaction (including, without limitation, the expenses of the distribution of any such securities registered for sale under the 1933 Act) will, to the extent not payable by an Adviser under any agreement with the Company or the Private Funds, be shared by the Company and the Private Funds in proportion to the relative amounts of the securities held or being acquired or disposed of, as the case may be.

13. Any transaction fee (including break-up or commitment fees but excluding broker's fees contemplated by section 17(e) or 57(k) of the Act or received in connection with a Co-Investment Transaction will be distributed to the Company and the Private Funds on a pro rata basis, based on the amounts they invested or committed, as the case may be, in such Co-Investment Transaction. If any transaction fee is to be held by an Adviser to a Private Fund pending consummation of the Co-Investment Transaction, the fee will be deposited into an account maintained by such Adviser at a bank or banks having the qualifications prescribed in section 26(a)(I) of the Act, and such account will earn a competitive rate of interest that will also be divided pro rata among the Company and the participating Private Funds based on the amounts they invest in such Co-Investment Transaction. None of the Private Funds, Advisers of the Private Funds nor any affiliated person of the Company will receive additional compensation or remuneration of any kind as a result of, or in connection with, a Co-Investment Transaction (other than (i) in the case of the Company and the participating Private Funds, the pro rata transaction fees described above and fees or other compensation described in condition 2(c)(iii)(C) and (ii) in the case of the Advisers, investment advisory fees paid in accordance with the Advisory Agreements).

For the Commission, by the Division of Investment Management, under delegated authority.

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–14204 Filed 6–17–14; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–72374; File No. SR–EDGX–2014–16]

Self-Regulatory Organizations; EDGX Exchange, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to Amendments to the EDGX Exchange, Inc. Fee Schedule

June 12, 2014.

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 June 2, 2014, EDGX Exchange, Inc. (the ''Exchange'' or ''EDGX'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II and III 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 its fees and rebates applicable to Members [3] of the Exchange pursuant to EDGX Rule 15.1(a) and (c) (''Fee Schedule'') to: (i) Delete Flag RC, which routes to the National Stock Exchange, Inc. (''NSX'') and adds liquidity; and (ii) make a corrective change to the definition of Average Daily Trading Volume (''ADV'') to state that ADV includes shares routed by the Exchange. The text of the proposed rule change is available on the Exchange's Internet Web site at *www.directedge.com*, at the Exchange's principal office, and at the Public Reference Room of the Commission.

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 these statements may be examined at the places specified in Item IV below. The self-regulatory organization 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 the Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend its Fee Schedule to: (i) Delete Flag RC, which routes to the NSX and adds liquidity; and (ii) make a corrective change to the definition of ADV to state that ADV includes shared routed by the Exchange.

Flag RC

The Exchange proposes to amend its Fee Schedule to delete Flag RC, which routes to the NSX and adds liquidity, in response to the NSX's announcement that it will cease market operations and its last day of trading will be Friday, May 30, 2014.[4] The Exchange currently charges a fee of $0.0001 per share in securities priced at or above $1.00 and no fee in securities priced below $1.00 for Members' orders that yield Flag RC. The fee for orders that yield Flag RC represents a pass through of the rate that DE Route, the Exchange's affiliated routing broker-dealer, is charged for routing orders that add liquidity to NSX. As of June 1, 2014, the Exchange, via DE Route, will no longer be able to route orders to NSX because it ceased operations, and, therefore, proposes to remove Flag RC from its Fee Schedule.

ADV

The Exchange proposes to make a corrective change to the definition of ADV to state that a Member's ADV *does*

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[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] The term ''Member'' is defined as ''any registered broker or dealer, or any person associated with a registered broker or dealer, that has been admitted to membership in the Exchange. A Member will have the status of a ''member'' of the Exchange as that term is defined in Section 3(a)(3) of the Act.'' *See* Exchange Rule 1.5(n).

[4] *See* Securities Exchange Act Release No. 72107 (May 6, 2014), 79 FR 27017 (May 12, 2014) (SR–NSX–2014–14) (Notice of Filing and Immediate Effectiveness of Proposed Rule Change to Cease Trading on Its Trading System).

include shares that are routed to other trading centers. The Exchange determines the liquidity adding rebate that it will provide to Members based on the Exchange's tiered pricing structure based on the calculation of ADV, and/or average daily Total Consolidated Volume.[5] On May 1, 2014, the Exchange harmonized its definition of ADV with that contained in the BATS Exchange, Inc. (''BATS'') and BATS–Y Exchange, Inc. (''BYX'') fee schedules by amending the definitions of ADV to state that routed shares are not included in ADV calculation.[6]

The Exchange's Fee Schedule currently states that Flag 7, which is yielded on orders routed during the pre and post market sessions, is considered when determining the liquidity adding rebate that the Exchange will provide to Members based on its tiered pricing structure. In harmonizing its definition of ADV with BATS and BYX, the Exchange mistakenly included a provision that excluded routed shares from the definition of ADV, thereby creating a conflict with the above provision in the Fee Schedule stating that Flag 7 is considered when determining the liquidity adding rebate under its tiered pricing structure. The Exchange now seeks to make a corrective change to the definition of ADV to state that routed orders are included in a Member's ADV calculation. The proposed rule change is designed to resolve a conflict in the Fee Schedule between the definition of ADV and the inclusion of orders that yield Flag 7 when determining the liquidity adding rebate under its tiered pricing structure. The Exchange notes that its proposal conforms to an existing practice and does not modify the fees or rebate that the Exchange has been providing its Members for achieving tier-based pricing.

Implementation Date

The Exchange proposes to implement these amendments to its Fee Schedule on June 2, 2014.

2. *Statutory Basis*

The Exchange believes that the proposed rule change is consistent with the objectives of Section 6 of the Act,[7] in general, and furthers the objectives of Section 6(b)(4),[8] in particular, as it is designed to provide for the equitable allocation of reasonable dues, fees and other charges among its Members and other persons using its facilities.

Flag RC

The Exchange believes that its proposal to delete Flag RC in its Fee Schedule represents an equitable allocation of reasonable dues, fees, and other charges among Members and other persons using its facilities. The proposed change is in response to NSX's announcement that it will cease market operations and its last day of trading will Friday, May 30, 2014.[9] As of June 1, 2014, the Exchange, via DE Route, will no longer be able to route orders to NSX and, therefore, proposes to remove Flag RC from its Fee Schedule. The Exchange believes that the proposed amendment is intended to make the Fee Schedule clearer and less confusing for investors and eliminate potential investor confusion, thereby removing impediments to and perfecting the mechanism of a free and open market and a national market system, and, in general, protecting investors and the public interest.

ADV

The Exchange believes that correcting an inadvertent error in the definition of ADV with regard to routed orders is reasonable because it will increase the level of transparency on the Exchange's Fee Schedule and improve the Exchange's ability to effectively convey the criteria necessary to achieve tier-based pricing and resolve a conflict in the Fee Schedule between the definition of ADV and the inclusion of orders that yield Flag 7 when determining the liquidity adding rebate under its tiered pricing structure. The Exchange notes that its proposal conforms to an existing practice and does not modify the rebates or fees that the Exchange provides its Members for achieving tier-based pricing. The Exchange has historically in practice and will continue to include routed shares when calculating a Member's ADV by including orders that yield Flag 7 when determining the liquidity adding rebate under its tiered pricing structure. Other than this correction, which resolves a conflict in the Fee Schedule, the remainder of the definition of ADV would remain unchanged. Lastly, the Exchange also believes that these proposed amendments are non-discriminatory because they apply uniformly to all Members.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange believes its proposed amendments to its Fee Schedule would not impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act. The Exchange does not believe that the proposed change represents a significant departure from previous pricing offered by the Exchange or pricing offered by the Exchange's competitors. Additionally, Members may opt to disfavor EDGX's pricing if they believe that alternatives offer them better value. Accordingly, the Exchange does not believe that the proposed change will impair the ability of Members or competing venues to maintain their competitive standing in the financial markets.

Flag RC

The Exchange believes that its proposal to delete Flag RC in its Fee Schedule would not affect intermarket nor intramarket competition because this change is not designed to amend any fee or rebate or alter the manner in which the Exchange assesses fees or calculates rebates. It is simply proposed in response to NSX announcement that it will cease market operations and its last day of trading will be Friday, May 30, 2014.[10]

ADV

The Exchange believes that correcting an inadvertent error in the definition of ADV would not impose a burden on intermarket or intramarket competition because it simply conforms to an existing practice by resolving a conflict in the Fee Schedule and does not modify the rebates or fees that the Exchange provides its Members for achieving tier-based pricing. The Exchange has historically in practice and will continue to include routed shares when calculating a Member's ADV by including orders that yield Flag 7 when determining the liquidity adding rebate under its tiered pricing structure. Other than this correction, the

[5] As provided in the Fee Schedule, ''TCV'' is currently defined as the volume reported by all exchanges and trade reporting facilities to the consolidated transaction reporting plans for Tapes A, B and C securities for the month in which the fees are calculated, excluding volume on any day that the Exchange experiences an Exchange System Disruption or the Russell Reconstitution Day.

[6] *See* Securities Exchange Act Release No. 72002 (April 23, 2014), 79 FR 24028 (April 29, 2014) (SR–EDGX–2014–10). The Exchange also amended the definition of ADV to exclude shares on: (i) Any day that the Exchange's system experiences a disruption that lasts for more than 60 minutes during Regular Trading Hours (''Exchange System Disruption''); and (ii) the last Friday in June (the ''Russell Reconstitution Day''). *Id.*

[7] 15 U.S.C. 78f.

[8] 15 U.S.C. 78f(b)(4).

[9] *See* Securities Exchange Act Release No. 72107 (May 6, 2014), 79 FR 27017 (May 12, 2014) (SR–NSX–2014–14) (Notice of Filing and Immediate Effectiveness of Proposed Rule Change to Cease Trading on Its Trading System).

[10] *See* Securities Exchange Act Release No. 72107 (May 6, 2014), 79 FR 27017 (May 12, 2014) (SR–NSX–2014–14) (Notice of Filing and Immediate Effectiveness of Proposed Rule Change to Cease Trading on Its Trading System).

remainder of the definition of ADV would remain unchanged.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The Exchange has not solicited, and does not intend to solicit, comments on this proposed rule change. The Exchange has not received any unsolicited written comments from Members or other interested parties.

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) of the Act [11] and Rule 19b–4(f)(2) [12] thereunder. 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.

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–EDGX–2014–16 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–EDGX–2014–16. 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 Web site (*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 Web site 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; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–EDGX–2014–16, and should be submitted on or before July 9, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[13]

Kevin M. O'Neill,

Deputy Secretary.

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[11] 15 U.S.C. 78s(b)(3)(A).

[12] 17 CFR 240.19b–4(f)(2).

[13] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–72382; File No. SR–NASDAQ–2014–041]

Self-Regulatory Organizations; The NASDAQ Stock Market LLC; Order Approving a Proposed Rule Change, as Modified by Amendment No. 1 Thereto, To List and Trade of Shares of the First Trust Enhanced Short Maturity ETF of First Trust Exchange-Traded Fund IV

June 12, 2014.

I. Introduction

On April 11, 2014, The NASDAQ Stock Market LLC (''Exchange'' or ''Nasdaq'') 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 relating to the listing and trading of shares (''Shares'') of the First Trust Enhanced Short Maturity ETF (''Fund'') of First Trust Exchange-Traded Fund IV (''Trust''). On April 24, 2014, the Exchange filed Amendment No. 1 to the proposed rule change.[3] The Commission published for comment in the **Federal Register** notice of the proposed rule change, as modified by Amendment No. 1 thereto, on May 1, 2014.[4] The Commission received no comments on the proposed rule change. This order approves the proposed rule change, as modified by Amendment No. 1 thereto.

II. Description of the Proposed Rule Change

The Exchange proposes to list and trade Shares pursuant to Nasdaq Rule 5735, which governs the listing and trading of Managed Fund Shares.[5] The Exchange deems the Shares to be equity securities, rendering trading in the Shares subject to the Exchange's existing rules governing the trading of equity securities.[6]

The Shares will be offered by the Trust, which is organized as a Massachusetts business trust and is registered with the Commission as an investment company.[7] First Trust Advisors L.P. is the investment adviser (''Adviser'') to the Fund. First Trust Portfolios L.P. is the principal underwriter and distributor of the Shares (''Distributor''). The Bank of New York Mellon Corporation will act as the administrator, accounting agent, custodian, and transfer agent to the Fund. The Adviser is affiliated with the

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] In Amendment No. 1, the Exchange: (1) Clarified that the Fund (defined below) will limit its investments in asset-backed securities and non-agency mortgage-backed securities (in the aggregate) to 20% of its net assets; (2) modified its description of how asset-backed or mortgage-backed securities will be priced in certain circumstances; and (3) made certain grammatical corrections.

[4] *See* Securities Exchange Act Release No. 72030 (April 25, 2014), 79 FR 24765 (''Notice'').

[5] Under Nasdaq's Rules, a Managed Fund Share is a security that (a) represents an interest in a registered investment company (''Investment Company'') organized as an open-end management investment company or similar entity, that invests in a portfolio of securities selected by the Investment Company's investment adviser consistent with the Investment Company's investment objectives and policies; (b) is issued in a specified aggregate minimum number in return for a deposit of a specified portfolio of securities and/or a cash amount with a value equal to the next determined net asset value; and (c) when aggregated in the same specified minimum number, may be redeemed at a holder's request, which holder will be paid a specified portfolio of securities and/or cash with a value equal to the next determined net asset value. *See* Nasdaq Rule 5735(c)(1).

[6] *See* Notice, *supra* note 4, 79 FR at 24770.

[7] The Trust is registered under the Investment Company Act of 1940 (''1940 Act''). *See* Post-Effective Amendment No. 66 to Registration Statement on Form N–1A for the Trust, dated April 10, 2014 (File Nos. 333–174332 and 811–22559) (''Registration Statement''). The Exchange represents that the Trust has obtained certain exemptive relief under the 1940 Act. *See* Investment Company Act Release No. 30029 (April 10, 2012) (File No. 812–13795) (''Exemptive Order'').

Distributor, a broker-dealer. As required by Nasdaq Rule 5735(g),[8] the Adviser has implemented a firewall with respect to its broker-dealer affiliate regarding access to information concerning the composition of or changes to the portfolio.[9]

First Trust Enhanced Short Maturity ETF[10]

The investment objective of the Fund will be to seek current income, consistent with preservation of capital and daily liquidity. Under normal market conditions,[11] the Fund will seek to achieve its investment objective by investing in a portfolio of U.S. dollar-denominated fixed- and variable-rate[12] instruments (collectively, ''Fixed Income Securities'') issued by U.S. and non-U.S. public- and private-sector entities. The Fund will hold Fixed Income Securities of at least 13 non-affiliated issuers.

Principal Investments

The Fund intends to achieve its investment objective by investing, under normal market conditions, at least 80% of its net assets in a portfolio of U.S. dollar-denominated Fixed Income Securities issued by U.S. and non-U.S. public- and private-sector entities. At least 80% of the Fund's net assets will be invested in Fixed Income Securities that are, at the time of purchase, investment grade. Fixed Income Securities will include the following types of fixed- and variable-rate debt securities: corporate[13] and government bonds and notes; agency securities; instruments of non-U.S. issuers in developed markets; privately-issued securities;[14] asset-backed securities;[15] mortgage-backed securities;[16] municipal bonds; money market securities; and investment companies[17] (including investment companies advised by the Adviser) that invest primarily in the foregoing types of Fixed Income Securities. The Fund will limit its investments in asset-backed securities and non-agency mortgage-backed securities (in the aggregate) to 20% of its net assets.[18]

Under normal market conditions, the Fund's duration[19] is expected to be below one year and the maturity[20] of the Fund's portfolio is expected to be below three years.

Other Investments

Under normal market conditions, the Fund will invest primarily in the Fixed Income Securities described above to meet its investment objective. In addition, the Fund may invest up to 20% of its net assets in floating rate loans. The floating rate loans in which the Fund will invest will represent amounts borrowed by companies or other entities from banks and other lenders and a significant portion of such floating rate loans may be rated below investment grade or unrated. Floating rate loans held by the Fund may be senior or subordinate obligations of the borrower and may or may not be secured by collateral.

Investment Restrictions

The Fund will not invest 25% or more of the value of its total assets in securities of issuers in any one industry. This restriction does not apply to (a) obligations issued or guaranteed by the U.S. government, its agencies or instrumentalities or (b) securities of other investment companies.

The Fund may hold up to an aggregate amount of 15% of its net assets in illiquid assets (calculated at the time of investment), including Rule 144A securities deemed illiquid by the Adviser. The Fund will monitor its portfolio liquidity on an ongoing basis to determine whether, in light of current circumstances, an adequate level of liquidity is being maintained, and will consider taking appropriate steps in order to maintain adequate liquidity if, through a change in values, net assets, or other circumstances, more than 15% of the Fund's net assets are held in illiquid assets. Illiquid assets include securities subject to contractual or other restrictions on resale and other instruments that lack readily available markets as determined in accordance with Commission staff guidance.[21]

The Fund will not invest in non-U.S. equity securities.

III. Discussion and Commission's Findings

After careful review, the Commission finds that the proposed rule change, as modified by Amendment No. 1 thereto, is consistent with the requirements of Section 6 of the Act[22] and the rules and

[8] Nasdaq Rule 5735(g) also requires that Adviser personnel who make decisions regarding the Fund's portfolio be subject to procedures designed to prevent the use and dissemination of material, non-public information regarding the Fund's portfolio.

[9] Additionally, the Exchange represents that, in the event (a) the Adviser becomes newly affiliated with a broker-dealer, or (b) any new adviser or sub-adviser becomes affiliated with a broker-dealer, it will implement a fire wall with respect to such broker-dealer regarding access to information concerning the composition of or changes to the portfolio, and it will be subject to procedures designed to prevent the use and dissemination of material, non-public information regarding such portfolio.

[10] Additional information regarding the Trust, the Fund, and the Shares, including investment strategies, risks, creation and redemption procedures, fees, Fund holdings disclosure policies, distributions and taxes, among other things, is included in the Notice and Registration Statements, as applicable. *See* Notice and Registration Statement, *supra* notes 4 and 7, respectively.

[11] According to the Exchange, the term ''under normal market conditions includes, but is not limited to, the absence of adverse market, economic, political or other conditions, including extreme volatility or trading halts in the fixed income markets or the financial markets generally; operational issues causing dissemination of inaccurate market information; or *force majeure* type events such as systems failure, natural or man-made disaster, act of God, armed conflict, act of terrorism, riot or labor disruption or any similar intervening circumstance. For temporary defensive purposes, during the initial invest-up period and during periods of high cash inflows or outflows, the Fund may depart from its principal investment strategies; for example, it may hold a higher than normal proportion of its assets in cash. During such periods, the Fund may not be able to achieve its investment objective. The Fund may adopt a defensive strategy when the Adviser believes securities in which the Fund normally invests have elevated risks due to political or economic factors and in other extraordinary circumstances.

[12] For these purposes, the term ''variable-rate'' also includes similar terms such as ''floating-rate'' and ''adjustable-rate.''

[13] While the Fund is permitted to invest without restriction in corporate bonds, the Adviser expects that, under normal market conditions, generally, with respect to at least 75% of the Fund's portfolio, a corporate bond will have, at the time of original issuance, $100 million or more par amount outstanding to be considered as an eligible investment.

[14] ''Privately-issued securities'' for these purposes generally includes Rule 144A securities and, in this context, may include both mortgage-backed and non-mortgage Rule 144A securities.

[15] Asset-backed securities are Fixed Income Securities that are backed by a pool of assets. The Fund currently intends to invest in asset-backed securities that are consumer asset-backed securities.

[16] Mortgage-backed securities are Fixed Income Securities that are backed by a pool of mortgage loans. There are a wide variety of mortgage-backed securities involving commercial or residential, fixed-rate or adjustable-rate mortgages and mortgages issued by banks or government agencies.

[17] Currently, the Fund anticipates investing only in registered open-end investment companies that are listed and traded in the U.S. on registered exchanges (*i.e.,* other exchange traded funds).

[18] *See* Amendment No. 1, *supra* note3. There is no limit applicable to agency mortgage-backed securities.

[19] Duration is a measure of the expected price volatility of a debt instrument as a result of changes in market rates of interest, based on, among other factors, the weighted average timing of the instrument's expected principal and interest payments. Duration differs from maturity in that it considers a security's yield, coupon payments, principal payments, call features and coupon adjustments in addition to the amount of time until the security finally matures.

[20] Maturity is measured relative to the type of security. For Fixed Income Securities (exclusive of asset-backed securities and mortgage-backed securities), maturity shall be calculated using dollar-weighted average maturity, which is calculated by taking the average length of time to maturity. For asset-backed securities and mortgage-backed securities, maturity shall be calculated using weighted average life, which is the estimated time to principal paydown for each underlying instrument held by the Fund, weighted according to the relative holdings per instrument.

[21] *See* Notice, *supra* note 4, 79 FR at 24768, n.26.

[22] 15 U.S.C. 78f.

regulations thereunder applicable to a national securities exchange.[23] In particular, the Commission finds that the proposal is consistent with Section 6(b)(5) of the Act,[24] which requires, among other things, that the Exchange's rules be 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. The Commission notes that the Fund and the Shares will be listed and traded on the Exchange pursuant to the initial and continued listing criteria in Nasdaq's Rule 5735.

The Commission finds that the proposal to list and trade the Shares on the Exchange is consistent with Section 11A(a)(1)(C)(iii) of the Act,[25] which sets forth Congress' finding that it is in the public interest and appropriate for the protection of investors and the maintenance of fair and orderly markets to assure the availability to brokers, dealers, and investors of information with respect to quotations for, and transactions in, securities. Information regarding market price and trading volume of the Shares will be continually available on a real-time basis throughout the day on brokers' computer screens and other electronic services. Quotation and last-sale information for the Shares will be available via Nasdaq proprietary quote and trade services, as well as in accordance with the Unlisted Trading Privileges and the Consolidated Tape Association plans for the Shares. Intraday executable price quotations on Fixed Income Securities and other assets not traded on an exchange will be available from major broker-dealer firms or market data vendors, as well as from automated quotation systems, published or other public sources, or online information services. For exchange-listed assets, intraday pricing information will be available directly from the applicable listing exchange. Intraday price information will also be available through subscription services, such as Bloomberg, Markit, and Thomson Reuters, which can be accessed by authorized participants and other investors.

The Commission believes that the proposal to list and trade the Shares is reasonably designed to promote fair disclosure of information that may be necessary to price the Shares appropriately and to prevent trading when a reasonable degree of transparency cannot be assured. The NAV of the Shares generally will be calculated once daily Monday through Friday as of the close of regular trading on the New York Stock Exchange, generally 4:00 p.m., Eastern time. On each business day, before commencement of trading in Shares in the Regular Market Session[26] on the Exchange, the Fund will disclose on its Web site the identities and quantities of the portfolio of securities and other assets (''Disclosed Portfolio'' as defined in Nasdaq Rule 5735(c)(2)) held by the Fund that will form the basis for the Fund's calculation of NAV at the end of the business day.[27] The Exchange will obtain a representation from the issuer of the Shares that the NAV per Share will be calculated daily and that the NAV and the Disclosed Portfolio will be made available to all market participants at the same time.[28] Moreover, the Intraday Indicative Value, available on the NASDAQ OMX Information LLC proprietary index data service, will be widely disseminated by one or more major market data vendors and broadly displayed at least every 15 seconds during the Regular Market Session.[29] Trading in Shares will be halted if the circuit breaker parameters in Nasdaq Rule 4120(a)(11) have been reached or because of market conditions or for reasons that, in the view of the Exchange, make trading in the Shares inadvisable, and trading in the Shares will be subject to Nasdaq Rule 5735(d)(2)(D), which sets forth circumstances under which trading in the Shares may be halted. The Exchange states that it has a general policy prohibiting the distribution of material, non-public information by its employees. Further, the Commission notes that the Reporting Authority that provides the Disclosed Portfolio must implement and maintain, or be subject to, procedures designed to prevent the use and dissemination of material, non-public information regarding the actual components of the portfolio.[30] The Adviser is affiliated with a broker-dealer and has implemented a firewall with respect to that broker-dealer regarding access to information concerning the composition and/or changes to the Fund's portfolio.[31]

Further, regarding trading in the Shares and the exchange-traded securities held by the Fund, the Commission notes that the Financial Industry Regulatory Authority (''FINRA'') will communicate as needed on behalf of the Exchange[32] with other markets and other entities that are members of the Intermarket Surveillance Group (''ISG''),[33] and FINRA may obtain trading information regarding trading in the Shares and the exchange-traded securities held by the Fund from such markets and other entities that are members of the ISG, which includes securities and futures exchanges, or from markets which the Exchange has in place a comprehensive surveillance sharing agreement.[34] Moreover, the Exchange states that FINRA will be able to access on its behalf, as needed, trade information for certain Fixed Income Securities held by the Fund reported to FINRA's Trade Reporting and Compliance Engine.[35] The Exchange states that trading in the Shares will be subject to the existing trading surveillances, administered by FINRA on behalf of the Exchange, which are designed to detect violations of Exchange rules and applicable federal securities laws, and represents that these procedures are adequate to properly monitor Exchange trading of the Shares in all trading sessions and to deter and detect violations of Exchange rules and applicable federal securities laws.[36]

In support of this proposal, the Exchange has made representations, including:

(1) The Shares will conform to the initial and continued listing criteria under Nasdaq Rule 5735.

(2) The Exchange has appropriate rules to facilitate transactions in the Shares during all trading sessions.

[23] 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).

[24] 17 U.S.C. 78f(b)(5).

[25] 15 U.S.C. 78k–1(a)(1)(C)(iii).

[26] *See* Nasdaq Rule 4120(b)(4) (describing the three trading sessions on the Exchange: (1) Pre-Market Session from 4 a.m. to 9:30 a.m., Eastern time; (2) Regular Market Session from 9:30 a.m. to 4 p.m. or 4:15 p.m., Eastern time; and (3) Post-Market Session from 4 p.m. or 4:15 p.m. to 8 p.m., Eastern time).

[27] Under accounting procedures to be followed by the Fund, trades made on the prior business day (''T'') will be booked and reflected in NAV on the current business day (''T+1''). Accordingly, the Fund will be able to disclose at the beginning of the business day the portfolio that will form the basis for the NAV calculation at the end of the business day.

[28] *See* Notice, *supra* note 4, 79 FR at 24770.

[29] *See id.*

[30] *See* Nasdaq Rule 5735(d)(2)(B)(ii).

[31] *See* note 9, *supra* and accompanying text.

[32] The Exchange states that, while FINRA surveils trading on the Exchange pursuant to a regulatory services agreement, the Exchange is responsible for FINRA's performance under this regulatory services agreement. *See* Notice, *supra* note 4, 79 FR at 24771, n.34.

[33] For a list of the current members of ISG, see *www.isgportal.org.* The Exchange states that not all components of the Disclosed Portfolio may trade on markets that are members of ISG or with which the Exchange has in place a comprehensive surveillance sharing agreement. *See id.* at 24771, n.35.

[34] *See id.* at 24771.

[35] *See id.*

[36] *See id.* at 24770–71.

(3) The Exchange represents that trading in the Shares will be subject to the existing trading surveillances, administered by FINRA on behalf of the Exchange, which are designed to detect violations of Exchange rules and applicable federal securities laws and that these procedures are adequate to properly monitor Exchange trading of the Shares in all trading sessions and to deter and detect violations of Exchange rules and applicable federal securities laws.

(4) Prior to the commencement of trading, the Exchange will inform its members in an Information Circular of the special characteristics and risks associated with trading the Shares. Specifically, the Information Circular will discuss the following: (a) The procedures for purchases and redemptions of Shares in Creation Units (and that Shares are not individually redeemable); (b) Nasdaq Rule 2310, which imposes suitability obligations on Nasdaq members with respect to recommending transactions in the Shares to customers; (c) how information regarding the Intraday Indicative Value is disseminated; (d) the risks involved in trading the Shares during the Pre-Market and Post-Market Sessions when an updated Intraday Indicative Value will not be calculated or publicly disseminated; (e) the requirement that members deliver a prospectus to investors purchasing newly issued Shares prior to or concurrently with the confirmation of a transaction; and (f) trading information.[37]

(5) For initial and continued listing, the Fund will be in compliance with Rule 10A–3 under the Act.[38]

(6) While the Fund is permitted to invest without restriction in corporate bonds, the Adviser expects that, under normal market conditions, generally, with respect to at least 75% of the Fund's portfolio, a corporate bond will have, at the time of original issuance, $100 million or more par amount outstanding to be considered as an eligible investment.

(7) The Fund may hold up to an aggregate amount of 15% of its net assets in illiquid assets (calculated at the time of investment), including Rule 144A securities deemed illiquid by the Adviser.

(8) The Fund will limit its investments in asset-backed securities and non-agency mortgage-backed securities (in the aggregate) to 20% of its net assets.

(9) The Fund will not invest in non-U.S. equity securities.

(10) A minimum of 100,000 Shares will be outstanding at the commencement of trading.

This approval order is based on all of the Exchange's representations, including those set forth in the Notice.

IV. Conclusion

For the foregoing reasons, the Commission finds that the proposed rule change is consistent with Section 6(b)(5) of the Act[39] and the rules and regulations thereunder applicable to a national securities exchange.

It is therefore ordered, pursuant to Section 19(b)(2) of the Act,[40] that the proposed rule change (SR–NASDAQ–2014–041), as modified by Amendment No. 1, be, and it hereby is, approved.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[41]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–14202 Filed 6–17–14; 8:45 am]

BILLING CODE 8011–01–P

[37] *See id.* at 24771.

[38] 17 CFR 240.10A–3.

[39] 15 U.S.C. 78f(b)(5).

[40] 15 U.S.C. 78s(b)(2).

[41] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–72375; File No. SR–EDGA–2014–14]

Self-Regulatory Organizations; EDGA Exchange, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to Amendments to the EDGA Exchange, Inc. Fee Schedule

June 12, 2014.

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 June 2, 2014, EDGA Exchange, Inc. (the ''Exchange'' or ''EDGA'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II and III 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 its fees and rebates applicable to Members[3] of the Exchange pursuant to EDGA Rule 15.1(a) and (c) (''Fee Schedule'') to: (i) Delete Flag RC, which routes to the National Stock Exchange, Inc. (''NSX'') and adds Liquidity; and (ii) make a corrective change to the definition of Average Daily Trading Volume (''ADV'') to state that ADV includes shared routed by the Exchange. The text of the proposed rule change is available on the Exchange's Internet Web site at *www.directedge.com,* at the Exchange's principal office, and at the Public Reference Room of the Commission.

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 these statements may be examined at the places specified in Item IV below. The self-regulatory organization 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 the Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend its Fee Schedule to: (i) Delete Flag RC, which routes to the NSX and adds liquidity; and (ii) make a corrective change to the definition of ADV to state that ADV includes shared routed by the Exchange.

Flag RC

The Exchange proposes to amend its Fee Schedule to delete Flag RC, which routes to the NSX and adds liquidity, in response to the NSX's announcement that it will cease market operations and its last day of trading will be Friday, May 30, 2014.[4] The Exchange currently

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] The term ''Member'' is defined as ''any registered broker or dealer, or any person associated with a registered broker or dealer, that has been admitted to membership in the Exchange. A Member will have the status of a ''member'' of the Exchange as that term is defined in Section 3(a)(3) of the Act.'' *See* Exchange Rule 1.5(n).

[4] *See* Securities Exchange Act Release No. 72107 (May 6, 2014), 79 FR 27017 (May 12, 2014) (SR–NSX–2014–14) (Notice of Filing and Immediate

charges a fee of $0.0001 per share in securities priced at or above $1.00 and no fee in securities priced below $1.00 for Members' orders that yield Flag RC. The fee for orders that yield Flag RC represents a pass through of the rate that DE Route, the Exchange's affiliated routing broker-dealer, is charged for routing orders that add liquidity to NSX. As of June 1, 2014, the Exchange, via DE Route, will no longer be able to route orders to NSX because it ceased operations, and, therefore, proposes to remove Flag RC from its Fee Schedule.

ADV

The Exchange proposes to make a corrective change to the definition of ADV to state that a Member's ADV *does* include shares that are routed to other trading centers. The Exchange determines the liquidity adding rebate that it will provide to Members based on the Exchange's tiered pricing structure based on the calculation of ADV, and/or average daily Total Consolidated Volume.[5] On May 1, 2014, the Exchange harmonized its definition of ADV with that contained in the BATS Exchange, Inc. (''BATS'') and BATS–Y Exchange, Inc. (''BYX'') fee schedules by amending the definitions of ADV to state that routed shares are not included in ADV calculation.[6]

The Exchange's Fee Schedule currently states that certain routed flags are considered when determining the liquidity adding rebate that the Exchange will provide to Members based on its tiered pricing structure.[7] In harmonizing its definition of ADV with BATS and BYX, the Exchange mistakenly included a provision that excluded routed shares from the definition of ADV, thereby creating a conflict with the above provision in the Fee Schedule stating that certain routed flags are considered when determining the liquidity adding rebate under its tiered pricing structure. The Exchange now seeks to make a corrective change to the definition of ADV to state that routed orders are included in a Member's ADV calculation. The proposed rule change is designed to resolve a conflict in the Fee Schedule between the definition of ADV and the inclusion of orders that yield certain routed flags when determining the liquidity adding rebate under its tiered pricing structure. The Exchange notes that its proposal conforms to an existing practice and does not modify the fees or rebate that the Exchange has been providing its Members for achieving tier-based pricing.

Implementation Date

The Exchange proposes to implement these amendments to its Fee Schedule on June 2, 2014

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with the objectives of Section 6 of the Act,[8] in general, and furthers the objectives of Section 6(b)(4),[9] in particular, as it is designed to provide for the equitable allocation of reasonable dues, fees and other charges among its Members and other persons using its facilities.

Flag RC

The Exchange believes that its proposal to delete Flag RC in its Fee Schedule represents an equitable allocation of reasonable dues, fees, and other charges among Members and other persons using its facilities. The proposed change is in response to NSX's announcement that it will cease market operations and its last day of trading will Friday, May 30, 2014.[10] As of June 1, 2014, the Exchange, via DE Route, will no longer be able to route orders to NSX and, therefore, proposes to remove Flag RC from its Fee Schedule. The Exchange believes that the proposed amendment is intended to make the Fee Schedule clearer and less confusing for investors and eliminate potential investor confusion, thereby removing impediments to and perfecting the mechanism of a free and open market and a national market system, and, in general, protecting investors and the public interest.

ADV

The Exchange believes that correcting an inadvertent error in the definition of ADV with regard to routed orders is reasonable because it will increase the level of transparency on the Exchange's Fee Schedule and improve the Exchange's ability to effectively convey the criteria necessary to achieve tier-based pricing and resolve a conflict in the Fee Schedule between the definition of ADV and the inclusion of orders that certain routed flags when determining the liquidity adding rebate under its tiered pricing structure. The Exchange notes that its proposal conforms to an existing practice and does not modify the rebates or fees that the Exchange provides its Members for achieving tier-based pricing. The Exchange has historically in practice and will continue to include routed shares when calculating a Member's ADV by including orders that yield certain routed flags when determining the liquidity adding rebate under its tiered pricing structure. Other than this correction, which resolves a conflict in the Fee Schedule, the remainder of the definition of ADV would remain unchanged. Lastly, the Exchange also believes that these proposed amendments are non-discriminatory because they apply uniformly to all Members.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange believes its proposed amendments to its Fee Schedule would not impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act. The Exchange does not believe that the proposed change represents a significant departure from previous pricing offered by the Exchange or pricing offered by the Exchange's competitors. Additionally, Members may opt to disfavor EDGA's pricing if they believe that alternatives offer them better value. Accordingly, the Exchange does not believe that the proposed change will impair the ability of Members or competing venues to maintain their competitive standing in the financial markets.

Flag RC

The Exchange believes that its proposal to delete Flag RC in its Fee Schedule would not affect intermarket nor intramarket competition because this change is not designed to amend any fee or rebate or alter the manner in which the Exchange assesses fees or

Effectiveness of Proposed Rule Change to Cease Trading on Its Trading System).

[5] As provided in the Fee Schedule, ''TCV'' is currently defined as the volume reported by all exchanges and trade reporting facilities to the consolidated transaction reporting plans for Tapes A, B and C securities for the month in which the fees are calculated, excluding volume on any day that the Exchange experiences an Exchange System Disruption or the Russell Reconstitution Day.

[6] *See* Securities Exchange Act Release No. 72002 (April 23, 2014), 79 FR 24028 (April 29, 2014) (SR–EDGX–2014–10). The Exchange also amended the definition of ADV to exclude shares on: (i) Any day that the Exchange's system experiences a disruption that lasts for more than 60 minutes during Regular Trading Hours (''Exchange System Disruption''); and (ii) the last Friday in June (the ''Russell Reconstitution Day''). *Id.*

[7] The Exchange's Fee Schedule states that the following routed flags are counted towards tiers: A, C, D, F, G, I, J, K, L, M, O, P, Q, R, S, T, U, X, Z, 2, 7, 8, 9, 10, BY, CL, PX, RA, RB, RC, RM, RR, RS, RT, RW, RX, RY, RZ and SW. See the Exchange's Fee Schedule available at *http://www.directedge.com/Trading/EDGAFeeSchedule.aspx* (dated May 1, 2014).

[8] 15 U.S.C. 78f.

[9] 15 U.S.C. 78f(b)(4).

[10] *See* Securities Exchange Act Release No. 72107 (May 6, 2014), 79 FR 27017 (May 12, 2014) (SR–NSX–2014–14) (Notice of Filing and Immediate Effectiveness of Proposed Rule Change to Cease Trading on Its Trading System).

calculates rebates. It is simply proposed in response to NSX announcement that it will cease market operations and its last day of trading will be Friday, May 30, 2014.[11]

ADV

The Exchange believes that correcting an inadvertent error in the definition of ADV would not impose a burden on intermarket or intramarket competition because it simply conforms to an existing practice by resolving a conflict in the Fee Schedule and does not modify the rebates or fees that the Exchange provides its Members for achieving tier-based pricing. The Exchange has historically in practice and will continue to include routed shares when calculating a Member's ADV by including orders that yield certain routed flags when determining the liquidity adding rebate under its tiered pricing structure. Other than this correction, the remainder of the definition of ADV would remain unchanged.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The Exchange has not solicited, and does not intend to solicit, comments on this proposed rule change. The Exchange has not received any unsolicited written comments from Members or other interested parties.

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) of the Act [12] and Rule 19b–4(f)(2) [13] thereunder. 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.

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.

[11] *See* Securities Exchange Act Release No. 72107 (May 6, 2014), 79 FR 27017 (May 12, 2014) (SR–NSX–2014–14) (Notice of Filing and Immediate Effectiveness of Proposed Rule Change to Cease Trading on Its Trading System).

[12] 15 U.S.C. 78s(b)(3)(A).

[13] 17 CFR 240.19b–4(f)(2).

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–EDGA–2014–14 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–EDGA–2014–14. 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 Web site (*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 Web site 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; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–EDGA–2014–14, and should be submitted on or before July 9, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[14]

Kevin M. O'Neill,

Deputy Secretary.

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[14] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–72371; File No. SR–BATS–2014–023]

Self-Regulatory Organizations; BATS Exchange, Inc.; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change To Extend the Penny Pilot Program

June 12, 2014.

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 June 4, 2014, BATS Exchange, Inc. (the ''Exchange'' or ''BATS'') filed with the Securities and Exchange Commission (the ''SEC'' or ''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. The Exchange has designated this proposal as a ''non-controversial'' proposed rule change pursuant to Section 19(b)(3)(A) of the Act [3] and Rule 19b–4(f)(6)(iii) thereunder,[4] which renders it effective upon filing with the Commission. 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 filed a proposal for the BATS Options Market (''BATS Options'') to extend through December 31, 2014, the Penny Pilot Program (''Penny Pilot'') in options classes in certain issues (''Pilot Program'') previously approved by the Commission.[5]

The text of the proposed rule change is available at the Exchange's Web site at *http://www.batstrading.com,* at the principal office of the Exchange, and at the Commission's Public Reference Room.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A).

[4] 17 CFR 240.19b–4(f)(6)(iii).

[5] The rules of BATS Options, including rules applicable to BATS Options' participation in the Penny Pilot, were approved on January 26, 2010. *See* Securities Exchange Act Release No. 61419 (January 26, 2010), 75 FR 5157 (February 1, 2010) (SR–BATS–2009–031). BATS Options commenced operations on February 26, 2010. The Penny Pilot was extended for BATS Options through June 30, 2014. *See* Securities Exchange Act Release No. 71082 (December 16, 2013), 78 FR 77177 (December 20, 2013) (SR–BATS–2013–064).

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 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 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 purpose of this filing is to extend the Penny Pilot, which was previously approved by the Commission, through December 31, 2014, and to provide a revised date for adding replacement issues to the Pilot Program. The Exchange proposes that any Pilot Program issues that have been delisted may be replaced on the second trading day following July 1, 2014. The replacement issues will be selected based on trading activity for the six month period beginning December 1, 2013, and ending May 31, 2014.

The Exchange represents that the Exchange has the necessary system capacity to continue to support operation of the Penny Pilot. The Exchange believes the benefits to public customers and other market participants who will be able to express their true prices to buy and sell options have been demonstrated to outweigh the increase in quote traffic.

2. Statutory Basis

The Exchange believes that its proposal is consistent with the requirements of the Act and the rules and regulations thereunder that are applicable to a national securities exchange, and, in particular, with the requirements of Section 6(b) of the Act.[6] In particular, the proposal is consistent with Section 6(b)(5) of the Act,[7] because it would promote just and equitable principles of trade, remove impediments to, and perfect the mechanism of, a free and open market and a national market system. The Exchange believes that the Pilot Program promotes just and equitable principles of trade by enabling public customers and other market participants to express their true prices to buy and sell options. Accordingly, the Exchange believes that the proposal is consistent with the Act because it will allow the Exchange to extend the Pilot Program prior to its expiration on June 30, 2014. The Exchange notes that this proposal does not propose any new policies or provisions that are unique or unproven, but instead relates to the continuation of an existing program that operates on a pilot basis.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule change will impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act. In this regard, the Exchange notes that the rule change is being proposed in order to continue the Pilot Program, which is a competitive response to analogous programs offered by other options exchanges. The Exchange believes this proposed rule change is necessary to permit fair competition among the options exchanges.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

The Exchange has neither solicited nor received written comments on 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.

A proposed rule change filed under Rule 19b–4(f)(6) normally does not become operative prior to 30 days after the date of the filing.[11] However, pursuant to Rule 19b–4(f)(6)(iii),[12] 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 waiving the 30-day operative delay is consistent with the protection of investors and the public interest because doing so will allow the Pilot Program to continue without interruption in a manner that is consistent with the Commission's prior approval of the extension and expansion of the Pilot Program and will allow the Exchange and the Commission additional time to analyze the impact of the Pilot Program.[13] Accordingly, the Commission designates the proposed rule change as operative upon filing with the Commission.[14]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov*. Please include File Number SR–BATS–2014–023 on the subject line.

Paper Comments

- Send paper comments in triplicate to Secretary, Securities and Exchange

[6] 15 U.S.C. 78f(b).

[7] 15 U.S.C. 78f(b)(5).

[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)(iii) requires the Exchange to give the Commission written notice of the Exchange's intent to file the proposed rule change along with a brief description and the 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 pre-filing requirement.

[12] 17 CFR 240.19b–4(f)(6)(iii).

[13] *See* Securities Exchange Act Release No. 61061 (November 24, 2009), 74 FR 62857 (December 1, 2009) (SR–NYSEArca–2009–44). *See also supra* note 5.

[14] For purposes only of waiving the operative delay for this proposal, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–BATS–2014–023. 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 Web site (*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 Web site 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; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–BATS–2014–023 and should be submitted on or before July 9, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[15]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–14196 Filed 6–17–14; 8:45 am]

BILLING CODE 8011–01–P

[15] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–72379; File No. SR–ISE–2014–30]

Self-Regulatory Organizations; International Securities Exchange, LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend the Schedule of Fees

June 12, 2014.

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 June 2, 2014, the International Securities Exchange, LLC (the ''Exchange'' or the ''ISE'') filed with the Securities and Exchange Commission the proposed rule change, as described in Items I, II, and III 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 the Substance of the Proposed Rule Change

The ISE proposes to amend the Schedule of Fees to increase (1) the route-out fee applicable to Priority Customer orders, and (2) the Priority Customer taker fee in Select Symbols for members that do not meet a new total affiliated Priority Customer ADV threshold. The text of the proposed rule change is available on the Exchange's Web site (*http://www.ise.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 these statements may be examined at the places specified in Item IV below. The self-regulatory organization 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 Schedule of Fees to increase (1) the route-out fee applicable to Priority Customer[3] orders, and (2) the Priority Customer taker fee in Select Symbols[4] for members that do not meet a new total affiliated Priority Customer average daily volume (''ADV'') threshold, each as described in more detail below. The fee changes discussed apply to both Standard Options and Mini Options traded on the Exchange. The Exchange's Schedule of Fees has separate tables for fees applicable to Standard Options and Mini Options. The Exchange notes that while the discussion below relates to fees for Standard Options, the fees for Mini Options, which are not discussed below, are and shall continue to be 1/10th of the fees for Standard Options.

1. Priority Customer Route-Out Fee

The Exchange charges a fee of $0.40 per contract and $0.55 per contract for executions of Priority Customer and Professional Customer[5] orders, respectively, for orders that are routed to one or more exchanges in connection with the Options Order Protection and Locked/Crossed Market Plan. This fee is charged in lieu of the regular taker fee. The Exchange now proposes to increase the Priority Customer route-out fee for orders subject to linkage handling to $0.45 per contract. The route-out fee for Professional Customer orders will remain at its current rate. The route-out fee offsets costs incurred by the Exchange in connection with using unaffiliated broker-dealers to access other exchanges for linkage executions. The proposed fee better reflects the costs to the Exchange associated with routing orders to away markets.

2. Priority Customer Taker Fee in Select Symbols

The Exchange currently assesses per contract transaction fees and provides rebates to market participants that add liquidity to or remove liquidity from the Exchange (''maker/taker fees and rebates'') in Select Symbols. The taker fee for removing liquidity in Select Symbols is $0.42 per contract for Market Maker[6] and Market Maker Plus[7] orders,

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] A ''Priority Customer'' is a person or entity that is not a broker/dealer in securities, and does not place more than 390 orders in listed options per day on average during a calendar month for its own beneficial account(s), as defined in ISE Rule 100(a)(37A).

[4] ''Select Symbols'' are options overlying all symbols listed on the ISE that are in the Penny Pilot Program.

[5] A ''Professional Customer'' is a person or entity that is not a broker/dealer and is not a Priority Customer.

[6] The term ''Market Makers'' refers to ''Competitive Market Makers'' and ''Primary Market Makers'' collectively. See ISE Rule 100(a)(25).

[7] A Market Maker Plus is a Market Maker who is on the National Best Bid or National Best Offer at least 80% of the time for series trading between $0.03 and $3.00 (for options whose underlying stock's previous trading day's last sale price was less than or equal to $100) and between $0.10 and $3.00 (for options whose underlying stock's previous trading day's last sale price was greater than $100) in premium in each of the front two expiration months. A Market Maker's single best

$0.45 per contract for Non-ISE Market Maker,[8] Firm Proprietary [9]/Broker-Dealer,[10] and Professional Customer orders, and $0.25 per contract for Priority Customer orders. The Exchange now proposes to increase the Priority Customer taker fee to $0.30 per contract for members that do not meet a new Priority Customer ADV threshold. In particular, members that do not execute a total affiliated Priority Customer ADV of at least 200,000 contracts in a given month will pay a Priority Customer taker fee of $0.30 per contract. Members that execute a total affiliated Priority Customer ADV of 200,000 or more contracts will continue to pay the current taker fee of $0.25 per contract. The Exchange is not proposing to modify the taker fees for any other market participants, which will remain at their current respective rates.

In connection with the above change, the Exchange further proposes to include the definition of total affiliated Priority Customer ADV in a separate footnote.[11] Currently, this definition is contained in footnote 11, which provides a higher Market Maker Plus maker rebate for Market Makers that achieve Market Maker Plus with a total affiliated Priority Customer ADV that equals or exceeds 200,000 contracts in a given month. As this definition is also applicable to the new discounted Priority Customer taker fee, the Exchange believes that it is appropriate to include it in a separate footnote. The Exchange is not proposing any substantive change to the definition of total affiliated Priority Customer ADV, which will continue to be calculated in the way that it is today for the Market Maker Plus tier calculation.[12]

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with the provisions of Section 6 of the Act,[13] in general, and Section 6(b)(4) of the Act,[14] in particular, in that it is designed to provide for the equitable allocation of reasonable dues, fees, and other charges among its members and other persons using its facilities.

1. Priority Customer Route-Out Fee

The Exchange believes the proposed Priority Customer route-out fee is reasonable and equitable as it provides the Exchange the ability to recover costs associated with using unaffiliated broker-dealers to route Priority Customer orders to other exchanges for linkage executions. The Exchange notes that a number of other exchanges currently charge a variety of routing related fees associated with orders that are subject to linkage handling. The Exchange also believes that the proposed fees are not unfairly discriminatory because these fees would be uniformly applied to all Priority Customer orders. In addition, the fees charged for Priority Customer linkage executions will continue to be lower than the fees charged to Professional Customer orders.

2. Priority Customer Taker Fee in Select Symbols

The Exchange is proposing to adopt a volume-based taker fee structure for Priority Customer orders in Select Symbols. Under the proposed structure, members that execute a Priority Customer ADV of 200,000 contracts or more in a calendar month will be eligible for a discounted taker fee. The Exchange currently provides a similar incentive as part of its Market Maker Plus program for members whose affiliates execute a total affiliated Priority Customer ADV of at least 200,000 contracts in a given month. The Exchange believes that charging lower fees to Priority Customer orders from members that execute more Priority Customer volume on the ISE is reasonable and equitable as this will attract additional Priority Customer order flow to the Exchange, which will ultimately benefit all market participants that trade on the ISE. The Exchange also believes that the new tiered taker fee is not unfairly discriminatory because all members can achieve the lower fee for their Priority Customer orders by executing the required Priority Customer volume on the ISE. Furthermore, while the Exchange is increasing the taker fee in Select Symbols for Priority Customer orders executed by members that do not meet the new volume threshold, these members will continue to pay taker fees for their Priority Customer orders that are lower than the fees charged to other market participants on the ISE, and that are within the range of fees assessed by other options exchanges.

Finally, as noted above, the Exchange is proposing to move the definition of total affiliated Priority Customer ADV to a separate footnote. The Exchange believes that this non-substantive change is appropriate to eliminate investor confusion since this definition will now apply to Priority Customer taker fees as discussed here.

The Exchange notes that it has determined to charge fees in Mini Options at a rate that is 1/10th the rate of fees and rebates the Exchange provides for trading in Standard Options. The Exchange believes it is reasonable and equitable and not unfairly discriminatory to assess lower fees to provide market participants an incentive to trade Mini Options on the Exchange. The Exchange believes the proposed fees are reasonable and equitable in light of the fact that Mini Options have a smaller exercise and assignment value, specifically 1/10th that of a standard option contract, and, as such, is providing fees for Mini Options that are 1/10th of those applicable to Standard Options.

B. Self-Regulatory Organization's Statement on Burden on Competition

In accordance with Section 6(b)(8) of the Act,[15] the Exchange does not believe that the proposed rule change will impose any burden on intermarket or intramarket competition that is not necessary or appropriate in furtherance of the purposes of the Act. The Exchange operates in a highly competitive market in which market participants can readily direct their order flow to competing venues. In such an environment, the Exchange must continually review, and consider adjusting, its fees to remain competitive with other exchanges. For the reasons described above, the Exchange believes

and single worst quoting days each month based on the front two expiration months, on a per symbol basis, will be excluded in calculating whether a Market Maker qualifies for this rebate, if doing so will qualify a Market Maker for the rebate.

[8] A ''Non-ISE Market Maker'' is a market maker as defined in Section 3(a)(38) of the Securities Exchange Act of 1934, as amended, registered in the same options class on another options exchange.

[9] A ''Firm Proprietary'' order is an order submitted by a member for its own proprietary account.

[10] A ''Broker-Dealer'' order is an order submitted by a member for a broker-dealer account that is not its own proprietary account.

[11] The Exchange also notes that certain reserved footnotes from a previous filing are still referenced in the body of Schedule of Fees. *See* Securities Exchange Act Release No. 71554 (February 14, 2014), 79 FR 9783 (February 20, 2014) (SR–ISE–2014–08). The Exchange proposes to remove these old references, which point to reserved footnotes that are now being replaced with new text in this filing.

[12] As currently calculated, Priority Customer ADV includes all volume in all symbols and order types. All eligible volume from affiliated Members will be aggregated in determining total affiliated Priority Customer ADV, provided there is at least 75% common ownership between the Members as reflected on each Member's Form BD, Schedule A. For purposes of determining total affiliated Priority Customer ADV, any day that the market is not open for the entire trading day may be excluded from such calculation. Volume in Standard Options and Mini Options will be combined to calculate Priority Customer ADV but Members will be charged or rebated for all Standard Options traded at the Standard Option rate and for all Mini Options traded at the Mini Option rate.

[13] 15 U.S.C. 78f.

[14] 15 U.S.C. 78f(b)(4).

[15] 15 U.S.C. 78f(b)(8).

that the proposed fee changes reflect this competitive environment.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The Exchange has not solicited, and does not intend to solicit, comments on this proposed rule change. The Exchange has not received any unsolicited written comments from members or other interested parties.

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 [16] and subparagraph (f)(2) of Rule 19b–4 thereunder,[17] because it establishes a due, fee, or other charge imposed by ISE.

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 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–ISE–2014–30 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–ISE–2014–30. 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 Web site (*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 Web site 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 such filing also will be available for inspection and copying at the principal office of the Exchange. All comments received will be posted without change; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–ISE–2014–30, and should be submitted on or before July 9, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[18]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–14200 Filed 6–17–14; 8:45 am]

BILLING CODE 8011–01–P

[16] 15 U.S.C. 78s(b)(3)(A)(ii).

[17] 17 CFR 240.19b–4(f)(2).

[18] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–72378; File No. SR–NASDAQ–2014–062]

Self-Regulatory Organizations; The NASDAQ Stock Market LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Relating to NASDAQ Options Market Fees and Rebates

June 12, 2014.

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 June 2, 2014, The NASDAQ Stock Market LLC (''NASDAQ'' or ''Exchange'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by NASDAQ. 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

NASDAQ proposes to modify Chapter XV, entitled ''Options Pricing,'' at Section 2 governing pricing for NASDAQ members using the NASDAQ Options Market (''NOM''), NASDAQ's facility for executing and routing standardized equity and index options. Specifically, NOM proposes amending the NOM Market Maker [3] Rebates to Add Liquidity in Penny Pilot [4] Options.

While the Exchange has designated the proposal as effective upon filing, the Exchange has designated that the change is operative on June 2, 2014.

The text of the proposed rule change is available on the Exchange's Web site at *http://nasdaq.cchwallstreet.com*, at the principal office of the Exchange, and

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] The term ''NOM Market Maker'' means a Participant that has registered as a Market Maker on NOM pursuant to Chapter VII, Section 2, and must also remain in good standing pursuant to Chapter VII, Section 4. In order to receive NOM Market Maker pricing in all securities, the Participant must be registered as a NOM Market Maker in at least one security. *See* Chapter XV. ''Participant'' means a firm, or organization that is registered with the Exchange pursuant to Chapter II of these Rules for purposes of participating in options trading on NOM as a ''Nasdaq Options Order Entry Firm'' or ''Nasdaq Options Market Maker''. *See* Chapter I, Section (a)(40).

[4] The Penny Pilot was established in March 2008 and was extended through December 31, 2014. *See* Securities Exchange Act Release Nos. 57579 (March 28, 2008), 73 FR 18587 (April 4, 2008) (SR–NASDAQ–2008–026) (notice of filing and immediate effectiveness establishing Penny Pilot); 60874 (October 23, 2009), 74 FR 56682 (November 2, 2009)(SR–NASDAQ–2009–091) (notice of filing and immediate effectiveness expanding and extending Penny Pilot); 60965 (November 9, 2009), 74 FR 59292 (November 17, 2009)(SR–NASDAQ–2009–097) (notice of filing and immediate effectiveness adding seventy-five classes to Penny Pilot); 61455 (February 1, 2010), 75 FR 6239 (February 8, 2010) (SR–NASDAQ–2010–013) (notice of filing and immediate effectiveness adding seventy-five classes to Penny Pilot); 62029 (May 4, 2010), 75 FR 25895 (May 10, 2010) (SR–NASDAQ–2010–053) (notice of filing and immediate effectiveness adding seventy-five classes to Penny Pilot); 65969 (December 15, 2011), 76 FR 79268 (December 21, 2011) (SR–NASDAQ–2011–169) (notice of filing and immediate effectiveness extension and replacement of Penny Pilot); 67325 (June 29, 2012), 77 FR 40127 (July 6, 2012) (SR–NASDAQ–2012–075) (notice of filing and immediate effectiveness and extension and replacement of Penny Pilot through December 31, 2012); 68519 (December 21, 2012), 78 FR 136 (January 2, 2013) (SR–NASDAQ–2012–143) (notice of filing and immediate effectiveness and extension and replacement of Penny Pilot through June 30, 2013); 69787 (June 18, 2013), 78 FR 37858 (June 24, 2013) (SR–NASDAQ–2013–082); and 72244 (May 23, 2014), 79 FR 31151 (May 30, 2014) (SR–NASDAQ–2014–056) (notice of filing and immediate effectiveness). *See also* NOM Rules, Chapter VI, Section 5.

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. 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 the Statutory Basis for, the Proposed Rule Change

1. Purpose

NASDAQ proposes to amend Chapter XV, Section 2 regarding the Tier 6 NOM Market Maker Rebates to Add Liquidity in Penny Pilot Options, to add another methodology by which a Participant can earn the rebate. NASDAQ proposes the amendment in order to continue to incentivize Participants to select NOM as a venue when directing order flow.

Rebates for Adding NOM Market Maker Liquidity

The Exchange currently pays NOM Market Maker Rebates to Add Liquidity based on a six tier rebate structure, which is found in Chapter XV, Section 2(1), as follows:

Monthly volume		Rebate to add liquidity
Tier 1	Participant adds NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options of up to 0.10% of total industry customer equity and ETF option average daily volume (''ADV'') contracts per day in a month.	$0.20
Tier 2	Participant adds NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options above 0.10% to 0.30% of total industry customer equity and ETF option ADV contracts per day in a month.	$0.25
Tier 3	Participant adds NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options above 0.30% to 0.60% of total industry customer equity and ETF option ADV contracts per day in a month.	$0.30
Tier 4	Participant adds NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options of above 0.60% of total industry customer equity and ETF option ADV contracts per day in a month.	$0.32 or $0.38 in the following symbols BAC, GLD, IWM, QQQ and VXX or $0.40 in SPY
Tier 5	Participant adds NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options of above 0.30% of total industry customer equity and ETF option ADV contracts per day in a month and qualifies for the Tier 7 or Tier 8 Customer and/or Professional Rebate to Add Liquidity in Penny Pilot Options.	$0.40
Tier 6	Participant adds NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options above 0.80% of total industry customer equity and ETF option ADV contracts per day in a month and qualifies for the Tier 7 or Tier 8 Customer and/or Professional Rebate to Add Liquidity in Penny Pilot Options.	$0.42

For purposes of qualifying for a NOM Market Maker Penny Pilot Options Rebate to Add Liquidity tier, the Exchange today uses a metric that is a percentage of total industry customer equity and exchange traded fund (''ETF'') option average daily volume (''ADV'') contracts per day in a month.[5] This percentage metric is graduated from Tier 1 (lowest percentage) through Tier 6 (highest percentage). For example, currently a Participant can earn the $0.20 Tier 1 rebate if he adds NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options of up to 0.10% of total industry customer equity and ETF option ADV contracts per day in a month; and can earn the $0.42 Tier 6 rebate if he adds NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options above 0.80% of total industry customer equity and ETF option ADV contracts per day in a month and qualifies for the Tier 7 or Tier 8 Customer,[6] and/or Professional[7] Rebate to Add Liquidity in Penny Pilot Options.

The Exchange proposes to amend the Tier 6 rebate to add an alternative to the current metric. Specifically, in addition to the current metric of above 0.80% of total industry customer equity and ETF option ADV where the NOM Market Maker also qualifies for the Tier 7 or Tier 8 Customer and/or Professional Rebate to Add Liquidity in Penny Pilot Options,[8] the Exchange proposes to add the alternate metric that a Participant may earn a Tier 6 rebate if he adds NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options above 0.90% of total industry customer equity and ETF option ADV contracts per day in a month.

With the proposed amendment, the Exchange would pay a Tier 6 $0.42 per contract rebate where a Participant adds NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options above 0.80% of total industry customer equity and ETF option ADV contracts per day in a month and qualifies for the Tier 7 or Tier 8 Customer and/or Professional Rebate to Add Liquidity in Penny Pilot Options, or Participant adds NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options above 0.90% of total industry customer equity and ETF option ADV contracts per day in a month. The Exchange is not amending the current qualification for the Tier 6

[5] *See* Securities Exchange Act Release No. 71703 (March 12, 2014), 79 FR 15172 (March 18, 2014) (SR–NASDAQ–2014–023) (order approving proposal to establish, among other things, the percentage metric).

[6] The term ''Customer'' means any transaction that is identified by a Participant for clearing in the Customer range at The Options Clearing Corporation (''OCC'') which is not for the account of broker or dealer or for the account of a ''Professional'' (as that term is defined in Chapter I, Section 1(a)(48)). *See* Chapter XV.

[7] The term ''Professional'' means any person or entity that (i) is not a broker or dealer in securities, and (ii) places more than 390 orders in listed options per day on average during a calendar month for its own beneficial account(s) pursuant to Chapter I, Section 1(a)(48). All Professional orders shall be appropriately marked by Participants. *See* Chapter XV.

[8] The Tier 7 rebate requires that a participant has Total Volume of 150,000 or more contracts per day in a month, of which 50,000 or more contracts per day in a month must be Customer and/or Professional liquidity in Penny Pilot Options. The Tier 8 rebate requires that the Participant adds Customer and/or Professional liquidity in Penny Pilot Options and/or Non-Penny Pilot Options of 0.75% or more of national customer volume in multiply-listed equity and ETF options classes in a month. *See* Chapter XV, Section 2(1).

NOM Market Maker rebate, but is simply adding an alternate method to qualify to earn a rebate.

In addition, the Exchange is proposing to delete an extraneous period in Tier 5, and thereby conform the punctuation in Tiers 1 through 6 of the NOM Market Maker Rebates to Add Liquidity in Penny Pilot Options.

The Exchange would continue to incentivize Participants, with NOM Market Maker rebate Tiers 1 through 6 as amended, to provide liquidity by paying specified rebates to those Participants that add NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options according to percentage metrics keyed to industry customer equity and ETF option average ADV contracts per day in a month.[9]

2. Statutory Basis

NASDAQ believes that its proposal to amend its Pricing Schedule is consistent with Section 6(b) of the Act [10] in general, and furthers the objectives of Section 6(b)(4) and (b)(5) of the Act [11] in particular, in that it provides for the equitable allocation of reasonable dues, fees and other charges among members and issuers and other persons using any facility or system which NASDAQ operates or controls, and is not designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

The Exchange's goal is to modify percentage eligibility thresholds where a Participant adds NOM Market Maker liquidity in order to continue to encourage market participants to direct a greater amount of NOM Market Maker liquidity to the Exchange. The Exchange's proposal does not eliminate rebates or the ability for market participants to earn rebates, but rather incorporates an additional way to earn rebates as noted herein.

The Exchange's proposal to amend Tier 6 of the NOM Market Maker Rebate to Add Liquidity in Penny Pilot Options is reasonable, equitable and not unfairly discriminatory for the reasons noted below.

The Exchange's proposal to adopt a new Tier 6 metric for Participants that add the highest level of NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options above 0.90% of total industry customer equity and ETF option ADV contracts per day in a month is equitable and not unfairly discriminatory because all eligible Participants that qualify for the additional Tier 6 NOM Market Maker Rebate to Add Liquidity metric will be uniformly paid the rebate.[12]

The Exchange would continue to incentivize Participants, with Tiers 1 through 6 NOM Market Maker Penny Pilot Options Rebates to Add Liquidity, as amended, to provide liquidity by paying specified rebates to those Participants that add NOM Market Maker liquidity in Penny Pilot Options and/or Non-Penny Pilot Options according to percentage metrics keyed to industry customer equity and ETF option average ADV contracts per day in a month. The proposed percentage metrics are dynamic in nature in that they reference total industry options contracts per day (rather than a static number of contracts per day),[13] and thereby make the Rebate structure similar for Customers and/or Professionals as well as for NOM Market Makers for similar products (e.g., Penny Pilot Options and Non-Penny Pilot Options).[14]

In addition, the Exchange believes it is reasonable to continue to use percentage metrics keyed to industry customer equity and ETF option average ADV contracts per day in a month because that is a benchmark that Participants are comfortable with in respect to Customer and Professional liquidity. Moreover, the Exchange believes that industry customer volume is a fair metric because it does not have the periodic spikes that may occur due to floor trading. Because NOM is an electronic market place with no trading floor, the Exchange believes that an industry volume metric is fair and reasonable.

B. Self-Regulatory Organization's Statement on Burden on Competition

NASDAQ does not believe that the proposed rule change will impose any burden on competition not necessary or appropriate in furtherance of the purposes of the Act.

The Exchange believes that adding an additional percentage eligibility metric in Tier 6 for Participants that bring the largest amount of liquidity should encourage Participants to direct additional NOM Market Maker order flow to the Exchange, and will dovetail with the existing metric in Tier 6.

Added liquidity benefits all market participants by providing more trading opportunities, which attracts market participants to the Exchange. An increase in the activity of these market participants in turn facilitates tighter spreads, which may cause an additional corresponding increase in order flow from other market participants. The Exchange believes that encouraging Participants to add NOM Market Maker liquidity creates competition among options exchanges because the Exchange believes that the rebates may cause market participants to select NOM as a venue to send order flow. The Exchange is continuing to offer rebates at specified percentage metrics for NOM Market Maker order flow being executed at the Exchange, which additional order flow should benefit other market participants.

The Exchange operates in a highly competitive market comprised of twelve U.S. options exchanges in which many sophisticated and knowledgeable market participants can readily and do send order flow to competing exchanges if they deem fee levels or rebate incentives at a particular exchange to be excessive or inadequate. These market forces support the Exchange belief that the rebate structure and tiers as amended are competitive with rebates and tiers in place on other exchanges. The Exchange believes that this competitive marketplace continues to impact the rebates present on the Exchange today and substantially influences the proposals set forth above.

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 foregoing rule change has become effective pursuant to Section

[9] The dynamic rebate structure, consisting of a percentage of total industry customer equity and ETF option ADV, is similar for Customer and/or Professional Penny Pilot Options as well as for NOM Market Makers for similar products (e.g., Penny Pilot Options and Non-Penny Pilot Options). The Exchange notes that if a Participant qualifies for two tiers, the higher rebate will be paid in a given month.

[10] 15 U.S.C. 78f(b).

[11] 15 U.S.C. 78f(b)(4), (5).

[12] The NOM Market Maker obligations and regulatory requirements remain unchanged. Pursuant to Chapter VII (Market Participants), Section 5 (Obligations of Market Makers), in registering as a market maker, an Options Participant commits himself to various obligations. Transactions of a Market Maker in its market making capacity must constitute a course of dealings reasonably calculated to contribute to the maintenance of a fair and orderly market, and Market Makers should not make bids or offers or enter into transactions that are inconsistent with such course of dealings. Further, all Market Makers are designated as specialists on NOM for all purposes under the Act or rules thereunder. *See* Chapter VII, Section 5.

[13] *See* supra note 5.

[14] The Exchange notes that if a Participant qualifies for two tiers, the higher rebate will be paid.

19(b)(3)(A)(ii) of the Act.[15] 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–2014–062 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–2014–062. 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 Web site (*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 Web site 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; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NASDAQ–2014–062, and should be submitted on or before July 9, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[16]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–14199 Filed 6–17–14; 8:45 am]

BILLING CODE 8011–01–P

[15] 15 U.S.C. 78s(b)(3)(A)(ii).

[16] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–72376; File No. SR–BATS–2014–021]

Self-Regulatory Organizations; BATS Exchange, Inc.; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change Related to Fees for Use of BATS Exchange, Inc.

June 12, 2014.

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 May 30, 2014, BATS Exchange, Inc. (the ''Exchange'' or ''BATS'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II and III below, which Items have been prepared by the Exchange. The Exchange has designated the proposed rule change as one establishing or changing a member due, fee, or other charge imposed by the Exchange under Section 19(b)(3)(A)(ii) of the Act[3] and Rule 19b–4(f)(2) thereunder,[4] which renders the proposed rule change effective upon filing with the Commission. 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 filed a proposal to amend the fee schedule applicable to Members[5] and non-members of the Exchange pursuant to BATS Rules 15.1(a) and (c). Changes to the fee schedule pursuant to this proposal are effective upon filing.

The text of the proposed rule change is available at the Exchange's Web site at *http://www.batstrading.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 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 the Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to modify the ''Options Pricing'' section of its fee schedule effective immediately, in order to amend a rebate and add two new tiers for Customer[6] orders that add liquidity to the Exchange's options platform (''BATS Options'') in options classes subject to the penny pilot program (''Penny Pilot Securities'').[7] More specifically, the Exchange is proposing to amend the fee schedule as follows: (i) Lower the standard rebate for Customer orders that add liquidity in Penny Pilot Securities; (ii) introduce a new tier for Customer orders that add liquidity in Penny Pilot Securities; and (iii) introduce a new cross-asset tier for Customer orders that add liquidity in Penny Pilot Securities.

The Exchange currently provides rebates for Customer orders that add liquidity to the BATS Options order book in Penny Pilot Securities pursuant to a tiered pricing structure, as described below, including a cross-asset tier, which provides enhanced rebates to

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A)(ii).

[4] 17 CFR 240.19b–4(f)(2).

[5] A Member is defined as ''any registered broker or dealer that has been admitted to membership in the Exchange.'' *See* Exchange Rule 1.5(n).

[6] As defined on the Exchange's fee schedule, a ''Customer'' order is any transaction identified by a Member for clearing in the Customer range at the Options Clearing Corporation (''OCC''), except for those designated as ''Professional''.

[7] The Exchange currently charges different fees and provides different rebates depending on whether an options class is an options class that qualifies as a Penny Pilot Security pursuant to Exchange Rule 21.5, Interpretation and Policy .01 or is a non-penny options class.

Members that meet certain volume thresholds on both BATS Options and the BATS equities trading platform (''BATS Equities''). The Exchange currently offers the following rebates per contract for a Customer order that adds liquidity in Penny Pilot Securities to the BATS Options order book: (i) $0.45 where the Member does not qualify for any additional rebates (the ''Lower Tier''); (ii) $0.48 where the Member has an ADV [8] equal to or greater than 0.30% of average TCV,[9] but less than 1.00% of average TCV (''Second Tier''); (iii) $0.50 where the Member has an ADV equal to or greater than 0.90% of average TCV and has on BATS Equities an ADAV [10] equal to or greater than 0.25% of average TCV (''Cross-Asset Tier''); [11] and (iv) $0.50 where the Member has an ADV equal to or greater than 1.00% of average TCV.

The Exchange is proposing to reduce the per contract rebate for the Lower Tier from $0.45 to $0.25. The Exchange is also proposing to create a new tier between the Lower Tier and the Second Tier in which a Member that has an ADV equal to or greater than 0.05% of average TCV, but less than 0.30% of average TCV will receive $0.45 per contract, the same rebate previous available in the Lower Tier. Finally, the Exchange is proposing to add an additional cross-asset tier in which a Member will receive $0.50 per contract where the Member has an ADV equal to or greater than 0.80% of average TCV and has on BATS Equities an ADAV equal to or greater than 0.50% of average TCV (the ''New Cross-Asset Tier'').

Implementation Date

The Exchange proposes to implement these amendments to its fee schedule on June 2, 2014.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with the requirements of the Act and the rules and regulations thereunder that are applicable to a national securities exchange, and, in particular, with the requirements of Section 6 of the Act.[12] Specifically, the Exchange believes that the proposed rule change is consistent with Section 6(b)(4) of the Act,[13] in that it provides for the equitable allocation of reasonable dues, fees and other charges among members and other persons using any facility or system which the Exchange operates or controls. The Exchange notes that it operates in a highly competitive market in which market participants can readily direct order flow to competing venues if they deem fee levels at a particular venue to be excessive.

Volume-based rebates and fees such as the ones maintained by BATS Options, and as amended by this proposal, have been widely adopted in the cash equities markets, and are reasonable and equitable because they are open to all Members on an equal basis and provide additional benefits or discounts that are reasonably related to the value to an exchange's market quality associated with higher levels of market activity, such as higher levels of liquidity provision and/or growth patterns, and introduction of higher volumes of orders into the price and volume discovery processes. Accordingly, the Exchange believes that the proposed changes to the Exchange's tiered pricing structure and incentives are not unfairly discriminatory because they are consistent with the overall goals of enhancing market quality. Similarly, the Exchange believes that continuing to base its tiered fee structure on overall TCV, rather than a static number of contracts irrespective of overall volume in the options industry, is a fair and equitable approach to pricing.

The Exchange notes that while the rebate for the Lower Tier is being reduced (from $0.45 to $0.25 per contract) such proposed new rebate is reasonable, fair and equitable in that it is the same as the rebate offered by NYSE Arca, Inc. and is $0.05 greater than rebate offered by the Nasdaq Stock Market LLC for Customer orders that add liquidity in Penny Pilot Securities that do not meet any other volume tiers. Further, the Exchange believes the reduction of the rebate for the Lower Tier is reasonable, fair and equitable because the Exchange is also proposing to introduce a new volume tier between the Lower Tier and the Second Tier with a relatively low volume threshold, where a Member will receive a $0.45 rebate per contract for Customer orders in Penny Pilot Securities where the Member has an ADV equal to or greater than 0.05% of average TCV. Thus, all Members with an ADV equal to or greater than 0.05%, but less than 0.30% of average TCV will receive the same rebate that they would have previously received pursuant to the Lower Tier for Customer orders that add liquidity in Penny Pilot Securities. The Exchange also believes that the new volume tier between the Lower Tier and Second Tier is reasonable, fair and equitable because it will encourage Members to add liquidity on BATS Options and because such Members will qualify for rebates pursuant to the new volume tier at a relatively low volume threshold. The Exchange further believes that the proposed amendment to rebates for the Lower Tier and the addition of a new tier between the Lower Tier and the Second Tier are fair and equitable and not unreasonably discriminatory because they will apply uniformly to all Members and are consistent with the overall goal of enhancing market quality on BATS Options as described above with respect to volume-based rebates and fees.

The Exchange's proposed New Cross-Asset Tier is reasonable, fair and equitable because it provides additional flexibility for Members to receive the highest possible rebate for Customer orders that add liquidity in Penny Pilot Securities. Compared to the Cross-Asset Tier, Members must meet a lower threshold on BATS Options (0.80% vs. 0.90%), but a higher threshold for BATS Equities (0.50% vs. 0.25%) in order to qualify for the New Cross-Asset Tier rebate of $0.50. Thus, the Exchange believes that the New Cross-Asset Tier is reasonable, fair and equitable because it will provide Members with a different volume profile on BATS Options and BATS Equities with the opportunity to qualify for the $0.50 per contract rebate, while simultaneously encouraging more Members to add liquidity on both BATS Equities and BATS Options. Further, the Exchange believes that the addition of

[8] As provided in the fee schedule, for purposes of BATS Options pricing, ''ADV'' means average daily volume calculated as the number of contracts added or removed, combined, per day. ADV is calculated on a monthly basis, excluding contracts added or removed on any day that the Exchange's system experiences a disruption that lasts for more than 60 minutes during regular trading hours (''Exchange System Disruption''). The fee schedule also provides that routed contracts are not included in ADV calculation.

[9] As provided in the fee schedule, for purposes of BATS Options pricing, ''TCV'' is total consolidated volume calculated as the volume reported by all exchanges to the consolidated transaction reporting plan for the month for which the fees apply, excluding volume on any day that the Exchange experiences an Exchange System Disruption.

[10] As provided in the fee schedule, for purposes of BATS Equities pricing, ''ADAV'' means average daily added volume calculated as the number of shares added per day. ADAV is calculated on a monthly basis, excluding routed shares as well as shares added on any day that the Exchange experiences an Exchange System Disruption and on the last Friday in June (the ''Russell Reconstitution Day'').

[11] As provided in the fee schedule, for purposes of BATS Equities pricing, ''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, excluding volume on any day that the Exchange experiences an Exchange System Disruption or the Russell Reconstitution Day.

[12] 15 U.S.C. 78f.

[13] 15 U.S.C. 78f(b)(4).

the New Cross-Asset Tier is fair and equitable and not unreasonably discriminatory because it is consistent with the overall goal of enhancing market quality on BATS Options and BATS Equities as described above with respect to volume-based rebates and fees.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange 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, as amended. With respect to the proposed new tiers and rebates, the Exchange does not believe that any such changes burden competition, but instead, enhance competition, as they are intended to increase the competitiveness of and draw additional volume to BATS Options, and, in the case of the New Cross-Asset Tier, also to BATS Equities. The Exchange also believes that the changes to the tiers as a whole will enhance competition because they are similar to pricing tiers currently available on other exchanges. As stated above, the Exchange notes that it operates in a highly competitive market in which market participants can readily direct order flow to competing venues if the deem fee structures to be unreasonable or excessive. As such, the proposal is a competitive proposal that is intended to add additional liquidity to the Exchange, which will, in turn, benefit the Exchange and all Exchange participants.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The Exchange has not solicited, and does not intend to solicit, comments on this proposed rule change. The Exchange has not received any written comments from members or other interested parties.

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 [14] and paragraph (f) of Rule 19b–4 thereunder.[15] At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include File Number SR–BATS–2014–021 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–BATS–2014–021. 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 Web site (*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 Web site 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; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–BATS–2014–021, and should be submitted on or before July 9, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[16]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–14198 Filed 6–17–14; 8:45 am]

BILLING CODE 8011–01–P

[14] 15 U.S.C. 78s(b)(3)(A)(ii).

[15] 17 CFR 240.19b–4(f).

[16] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–72381; File No. SR–NYSEARCA–2014–65]

Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Filing and Immediate Effectiveness of Proposed Rule Change Amending the NYSE Arca Equities Schedule of Fees and Charges for Exchange Services To Add an Additional Requirement To Qualify for Step Up Tier 3

June 12, 2014.

Pursuant to Section 19(b)(1) [1] of the Securities Exchange Act of 1934 (the ''Act'') [2] and Rule 19b–4 thereunder,[3] notice is hereby given that, on May 30, 2014, NYSE Arca, Inc. (the ''Exchange'' or ''NYSE Arca'') 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 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 proposes to [sic] amend the NYSE Arca Equities Schedule of Fees and Charges for Exchange Services (''Fee Schedule'') to add an additional requirement to qualify for Step Up Tier 3. The Exchange proposes to implement the fee change effective June 1, 2014. The text of the proposed rule change is available on the Exchange's Web site 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

[1] 15 U.S.C. 78s(b)(1).

[2] 15 U.S.C. 78a.

[3] 17 CFR 240.19b–4.

and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to amend the Fee Schedule to add an additional requirement to qualify for Step Up Tier 3, which was introduced into the Fee Schedule effective February 1, 2014.[4] The Exchange proposes to implement the fee change effective June 1, 2014.

Step Up Tier 3 in the Fee Schedule is applicable to an ETP Holder, including a Market Maker, that on a daily basis, measured monthly, directly executes providing volume (''Adding ADV'') during the billing month that is both (i) at least 0.20% of U.S. consolidated average daily volume (''U.S. CADV'') for the billing month and (ii) at least 0.125% taken as a percentage of U.S. CADV for the billing month over the ETP Holder's December 2013 Adding ADV taken as a percentage of U.S. CADV in December 2013 (''Baseline % CADV'').[5] For example, if U.S. CADV during the billing month is 7 billion shares, an ETP Holder's Adding ADV during the billing month would first need to be at least 14 million shares (i.e., at least 0.20% of U.S. CADV for the billing month). If U.S. CADV in December 2013 was 6 billion shares and an ETP Holder's December 2013 Adding ADV was 6 million shares, the ETP Holder's Baseline % CADV would be 0.10% (*i.e.,* the ETP Holder's December 2013 Adding ADV taken as a percentage of U.S. CADV in December 2013). The ETP Holder's Adding ADV during the billing month would therefore need to be at least 0.225% of U.S. CADV for the billing month (*i.e.,* Baseline % CADV of 0.10% plus at least 0.125%). This would equate to at least 15.75 million shares of Adding ADV, which would be a ''step up'' of 9.75 million shares.

A qualifying ETP Holder is eligible to receive a credit of $0.0004 per share for (i) Adding ADV in Tape A securities during the billing month taken as a percentage of U.S. CADV in Tape A securities in the billing month in excess of the Baseline % CADV in Tape A securities and (ii) Adding ADV in Tape C securities during the billing month taken as a percentage of U.S. CADV in Tape C securities in the billing month in excess of the Baseline % CADV in Tape C securities.[6] This credit would be in addition to the ETP Holder's Tiered or Basic Rate credit(s); provided, however, that such combined credit may not exceed $0.0034 per share.

The Exchange proposes that, in addition to the existing two requirements described above, to qualify for Step Up Tier 3 an ETP Holder would be required to directly execute Adding ADV during the billing month that is at least 40% over the ETP Holder's Baseline % CADV as a percentage of U.S. CADV for the billing month.[7] Continuing with the example above, if an ETP Holder's Baseline % CADV was 0.10%, the ETP Holder's Adding ADV during the billing month would need to be at least 0.14% of U.S. CADV for the billing month. If U.S. CADV for the billing month was 7 billion shares, the ETP Holder's Adding ADV during the billing month would need to be at least 9.8 million shares (*i.e.,* .0.14% multiplied by 7 billion). For an ETP Holder like this, with relatively low Baseline % CADV, this new requirement would not result in a new threshold that it would need to reach, because the 9.8 million shares would be less than the two existing required thresholds (*i.e.,* 14 million shares and 15.75 million shares, respectively).

However, and for further example, if the ETP Holder's Baseline % CADV instead was 0.60%, the ETP Holder's Adding ADV during the billing month would need to be at least 0.84% for the billing month. If U.S. CADV for the billing month was 7 billion shares, the ETP Holder's Adding ADV during the billing month would need to be at least 58.8 million shares (*i.e.,* 0.84% multiplied by 7 billion). Under the existing two requirements, this ETP Holder would be required to have Adding ADV during the billing month of 14 million shares or 50.75 million shares, respectively. This proposed new requirement would therefore result in the ETP Holder being required to have Adding ADV of 8.05 million shares greater than the higher of the two existing requirements and an overall ''step up'' of 22.8 million shares over its December 2013 Adding ADV.

No other changes to Step Up Tier 3, or the corresponding credit, would result from this proposed change.

The proposed change is not otherwise intended to address any other issues, and the Exchange is not aware of any problems that ETP Holders would have in complying with the proposed change.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with Section 6(b) of the Act,[8] in general, and furthers the objectives of Sections 6(b)(4) and 6(b)(5) of the Act,[9] in particular, because it provides for the equitable allocation of reasonable dues, fees, and other charges among its members, issuers and other persons using its facilities and does not unfairly discriminate between customers, issuers, brokers or dealers.

The existing requirement of Adding ADV during the billing month that is at least 0.20% of U.S. CADV establishes a minimum for any ETP Holder in order to qualify for Step Up Tier 3. The existing requirement of Adding ADV during the billing month of at least 0.125% taken as a percentage of U.S. CADV for the billing month over the ETP Holder's Baseline % CADV establishes a minimum amount that the ETP Holder must ''step up'' during the billing month, based on U.S. CADV during the billing month. In other words, as U.S. CADV during a particular billing month increases, the Adding ADV required of an ETP Holder would similarly increase (conversely, required Adding ADV would decrease if U.S. CADV during a particular billing month decreases). The proposed new requirement of Adding ADV during the billing month that is at least 40% over the ETP Holder's Baseline % CADV as a percentage of U.S. CADV for the billing month is reasonable because it would establish a minimum amount that each ETP Holder must ''step up'' during the billing month, but based

[4] *See* Securities Exchange Act Release No. 71503 (February 6, 2014), 79 FR 8524 (February 12, 2014) (SR–NYSEArca–2014–13).

[5] U.S. CADV means United States Consolidated Average Daily Volume for transactions reported to the Consolidated Tape, excluding odd lots through January 31, 2014 (except for purposes of Lead Market Maker pricing), and excludes volume on days when the market closes early. Transactions that are not reported to the Consolidated Tape are not included in U.S. CADV. An ETP Holder with zero Adding ADV in December 2013 (*e.g.,* a firm that became an ETP Holder after December 2013) is treated as having Baseline % CADV of zero for purposes of Step Up Tier 3.

[6] Orders that provide liquidity in Tape B securities count toward the ETP Holder's qualification for Step Up Tier 3, but such orders are not eligible for a credit under Step Up Tier 3. The Exchange's Fee Schedule includes a ''Tape B Step Up Tier'' that provides for a similar credit of $0.0004 per share only for orders in Tape B securities that provide liquidity.

[7] An ETP Holder with zero Adding ADV in December 2013 (*e.g.,* a firm that became an ETP Holder after December 2013) would be treated as having a Baseline % CADV of zero for purposes of the proposed new Step Up Tier 3 requirement. This proposed new requirement would therefore have no effect on such an ETP Holder. However, the existing two requirements would continue to apply.

[8] 15 U.S.C. 78f(b).

[9] 15 U.S.C. 78f(b)(4) and (5).

primarily on the ETP Holder's own activity during the baseline month of December 2013.

The Exchange believes that this proposed new requirement is also reasonable because it would further contribute to the goal of Step Up Tier 3—namely, encouraging ETP Holders to send additional orders to the Exchange for execution in order to qualify for an incrementally higher credit for such executions in Tape A and Tape C securities that add liquidity on the Exchange.[10] In this regard, the Exchange believes that this may incentivize ETP Holders to increase the orders sent directly to the Exchange and therefore provide liquidity that supports the quality of price discovery and promotes market transparency. The proposed new requirement is also reasonable because the level at which it would be set, *i.e.,* 40%, is consistent with a threshold within the Fee Schedule that similarly provides for specific pricing based on an ETP Holder's volume in the billing month compared to a particular ''baseline month.'' [11]

The Exchange also believes that the proposed additional requirement to qualify for Step Up Tier 3 credit is equitable and not unfairly discriminatory because it would incentivize ETP Holders to submit orders to the Exchange and would result in a credit that is reasonably related to an exchange's market quality that is associated with higher volumes. Moreover, like existing pricing on the Exchange that is tied to ETP Holder volume levels, the Exchange believes that the proposed qualifying threshold for Step Up Tier 3 is equitable and not unfairly discriminatory because it would be available for all ETP Holders, including Market Makers, on an equal and non-discriminatory basis. It is also equitable and not unfairly discriminatory that an ETP Holder with zero Adding ADV in December 2013 (*e.g.,* a firm that became an ETP Holder after December 2013) would be treated as having a Baseline % CADV of zero for purposes of the proposed Step Up Tier 3 because, as discussed above, the existing two requirements would continue to apply and would already require a higher Adding ADV from such an ETP Holder than if the Exchange applied a small, artificial Baseline % CADV for the ETP Holder.

Finally, the Exchange believes that it is subject to significant competitive forces, as described below in the Exchange's statement regarding the burden on competition.

For these reasons, the Exchange believes that the proposal is consistent with the Act.

B. Self-Regulatory Organization's Statement on Burden on Competition

In accordance with Section 6(b)(8) of the Act,[12] 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. Instead, the Exchange believes that the proposed change will encourage competition, including by attracting additional liquidity to the Exchange, which will make the Exchange a more competitive venue for, among other things, order execution and price discovery. In general, ETP Holders impacted by the proposed change may readily adjust their trading behavior to maintain or increase their credits or decrease their fees in a favorable manner, and will therefore not be disadvantaged in their ability to compete. More specifically, an ETP Holder could qualify for Step Up Tier 3 by providing sufficient adding liquidity to satisfy the proposed new volume requirement.

Also, the Exchange does not believe that the proposed change will impair the ability of ETP Holders or competing order execution venues to maintain their competitive standing in the financial markets. In this regard, the Exchange notes that existing pricing tiers of other exchanges similarly provide for credits for market participants that provide certain levels of liquidity on those exchanges.[13]

Finally, the Exchange notes that it operates in a highly competitive market in which market participants can readily favor competing venues if they deem fee levels at a particular venue to be excessive or rebate opportunities available at other venues to be more favorable. In such an environment, the Exchange must continually adjust its fees and rebates to remain competitive with other exchanges and with alternative trading systems that have been exempted from compliance with the statutory standards applicable to exchanges. Because competitors are free to modify their own fees and credits in response, and because market participants may readily adjust their order routing practices, the Exchange believes that the degree to which fee changes in this market may impose any burden on competition is extremely limited. As a result of all of these considerations, the Exchange does not believe that the proposed changes will impair the ability of member organizations or competing order execution venues to maintain their competitive standing in the financial markets.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change is effective upon filing pursuant to Section 19(b)(3)(A) [14] of the Act and subparagraph (f)(2) of Rule 19b–4 [15] thereunder, because it establishes a due, fee, or other charge imposed by the Exchange.

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) [16] 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–NYSEARCA–2014–65 on the subject line.

[10] *See supra* note 4 at 8525.

[11] *See, e.g.,* the ''Routable Order Tier'' within the Fee Schedule, pursuant to which an ETP Holder must provide, in part, an ADV of liquidity during the billing month across all Tapes that is equal to at least the ETP Holder's provide liquidity across all Tapes during a ''baseline'' month, plus 40%. *See also* Securities Exchange Act Release No. 69926 (July 3, 2013), 78 FR 41154 (July 9, 2013) (SR–NYSEArca–2013–67).

[12] 15 U.S.C. 78f(b)(8).

[13] *See, e.g.,* the ''Investor Support Program'' under NASDAQ Stock Market, LLC (''NASDAQ'') Rule 7014.

[14] 15 U.S.C. 78s(b)(3)(A).

[15] 17 CFR 240.19b–4(f)(2).

[16] 15 U.S.C. 78s(b)(2)(B).

Paper Comments

• Send paper comments in triplicate to Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEARCA–2014–65. 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 Web site (*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 Web site 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; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–NYSEARCA–2014–65 and should be submitted on or before July 9, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[17]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–14201 Filed 6–17–14; 8:45 am]

BILLING CODE 8011–01–P

[17] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–72377; File No. SR–BATS–2014–024]

Self-Regulatory Organizations; BATS Exchange, Inc.; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change Related to Fees for Use of BATS Exchange, Inc.

June 12, 2014.

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 June 4, 2014, BATS Exchange, Inc. (the ''Exchange'' or ''BATS'') filed with the Securities and Exchange Commission (''Commission'') the proposed rule change as described in Items I, II and III below, which Items have been prepared by the Exchange. The Exchange has designated the proposed rule change as one establishing or changing a member due, fee, or other charge imposed by the Exchange under Section 19(b)(3)(A)(ii) of the Act[3] and Rule 19b–4(f)(2) thereunder,[4] which renders the proposed rule change effective upon filing with the Commission. 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 filed a proposal to amend the fees applicable to securities listed on the Exchange pursuant to BATS Rule 14.13. Changes to the Exchange's fees pursuant to this proposal are effective upon filing.

The text of the proposed rule change is available at the Exchange's Web site at *http://www.batstrading.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 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 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

On August 30, 2011, the Exchange received approval of rules applicable to the qualification, listing, and delisting of companies on the Exchange,[5] which it modified on February 8, 2012 in order to adopt pricing for the listing of exchange traded products (''ETPs'') on the Exchange.[6] The Exchange proposes to modify Rule 14.13, entitled ''Company Listing Fees'' to reduce the entry fee for ETPs from $10,000 to $5,000 and to introduce new annual fees for ETPs that are not participating in the competitive liquidity provider program under Interpretation and Policy .02 to Rule 11.8 (the ''CLP Program''). For ETPs that are participating in the CLP Program, the Exchange proposes that the annual fees continue to be $35,000.

Currently, Rule 14.13(a)(A)(1)(C) provides that the entry fee for an ETP is $10,000, a fee that is assessed on the date of listing on the Exchange, except for a $5,000 non-refundable application fee which must be submitted along with the initial listing application. The Exchange proposes to instead charge a reduced entry fee of $5,000, which will continue to be non-refundable and due upon submission of the initial listing application. Consistent with current Rule 14.13 the Exchange is not proposing to charge an entry fee for transfer listings.

The Exchange is also proposing to introduce lower annual fees for ETPs. Currently, Rule 14.13 provides that the issuer of an ETP shall pay an annual fee of $35,000 for funds initially listed on the Exchange. Rule 14.13 provides that the issuer of an ETP that is a transfer listing shall pay an annual fee of $15,000. The Exchange is proposing to continue to charge $35,000 per year to the issuer of an ETP that is participating in the CLP Program. For all issuers of ETPs that are not participating in the CLP Program, including transfer listings, the Exchange proposes to charge the issuer on a quarterly basis based on the ETPs consolidated average daily volume (the ''CADV''), as defined below, during the quarter preceding the billing date.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A)(ii).

[4] 17 CFR 240.19b–4(f)(2).

[5] *See* Securities Exchange Act Release No. 65225 (August 30, 2011) 76 FR 55148 (September 6, 2011) (SR–BATS–2011–018).

[6] *See* Securities Exchange Act Release No. 72020 (April 25, 2014) 79 FR 24807 (May 1, 2014) (SR–BATS–2012–010).

Specifically, the Exchange is proposing to charge issuers of ETPs on a quarterly basis as follows:

CADV	Quarterly fee	Annual fee
0–10,000	$1,250	$5,000
10,001–40,000	2,000	8,000
40,001–80,000	3,000	12,000
80,001–150,000	3,750	15,000
150,001–400,000	4,500	18,000
Greater than 400,000	Free	Free

As proposed, CADV is calculated based on the three calendar months preceding the month for which the fees apply, meaning that when calculating the rebates that apply to a particular ETP, the CADV will be based on the three calendar months prior to the current trading month. For example, in calculating the annual fee that will be billable to the issuer of an ETP on the first day of the third quarter, the Exchange will look to the average daily volume reported for the ETP by all exchanges and trade reporting facilities to a consolidated transaction reporting plan for the second quarter, or April, May, and June. If that ETP was an initial listing on BATS (not a transfer listing from another listing market) and was listed beginning on May 15, the calculation of CADV would include all days from April 1 through May 14 with zero volume for each trading day. For transfer listings, the determination of the annual fees applicable to the ETP in the third quarter will be based on the CADV for the second quarter, regardless of where the ETP was listed during that period.

As noted above, the Exchange proposes to amend Rule 14.13 in order to make clear that the issuer of an ETP that participates in the CLP Program will continued to pay the Exchange an annual fee of $35,000.

Finally, the Exchange is proposing to correct a typographical error in the rule text. Specifically, the Exchange is proposing to amend the second sub-paragraph ''(a)'' in Rule 14.13 to ''(b)'' in order to make the rule more easily understandable.

Implementation Date

The Exchange proposes to implement these amendments to its fees on June 2, 2014.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with the requirements of the Act and the rules and regulations thereunder that are applicable to a national securities exchange, and, in particular, with the requirements of Section 6 of the Act.[7] Specifically, the Exchange believes that the proposed rule change is consistent with Section 6(b)(4) and 6(b)(5) of the Act,[8] in that it provides for the equitable allocation of reasonable dues, fees and other charges among issuers and it does not unfairly discriminate between customers, issuers, brokers or dealers.

The Exchange is proposing a tiered pricing structure for ETPs listed on the Exchange based on CADV that will significantly reduce listing fees for all new issuers, with the potential for free listing, which the Exchange believes are equitable and non-discriminatory because the tiers will be applied equally to all ETPs listed on the Exchange, including transfer listings. The Exchange also believes that continuing to charge $35,000 annually for ETPs that continue to participate in the CLP Program is equitable and non-discriminatory because the costs associated with operating the CLP Program are significantly higher than the anticipated costs associated with the new lead market maker program (the ''LMM Program''), into which newly listed ETPs will be automatically enrolled. Further, ETPs participating in the CLP Program may opt out of the CLP Program at any time in order to participate in the LMM Program and be charged the lower quarterly fees. Similarly, the Exchange believes that, while a transfer listing could possibly be charged a higher annual fee under the proposal ($18,000 vs. $15,000), the proposed changes are equitable and non-discriminatory because the pricing will be applied equally to all ETP listings, including transfer listings, and ETP transfer listings may also be eligible for reduced fees. Additionally, as described below, the annual fees are generally based on the cost to the Exchange associated with listing. The Exchange notes that it does not currently have any transfer listings and thus there are no BATS-listed ETPs that are eligible for continued annual fees of $15,000, as provided in current Rule 14.13, meaning that no existing ETP listings will be subject to a change in pricing and that any ETP that transfers to the Exchange in the future will have advanced notice of the proposed pricing.

The Exchange believes that it is equitable, reasonable, and non-discriminatory to charge increased listing fees to ETPs as their CADV increases. Under the LMM Program, the Exchange plans to offer enhanced rebates to any registered lead market maker for executions where such lead market maker has added displayed liquidity in a BATS-listed ETP for which they are designated as lead market maker, provided that they must meet specified quoting requirements in such BATS-listed ETP. The Exchange notes that as part of these enhanced rebates, it is planning to provide gradually *decreasing* rebates as the CADV increases in the BATS-listed ETP. While this may at first seem counterintuitive because the proposed listing fees for ETPs *increase* as the CADV increases, the total costs associated with operating the LMM Program for an ETP generally increase as the CADV increases because there are more shares executed that could potentially receive enhanced rebates. For example, where the Exchange pays a rebate of $0.0070 per share for a particular ETP with a CADV of 5,000, the Exchange could potentially pay $35 per day on average in enhanced rebates. Where the Exchange pays enhanced rebates of $0.0045 per share for an ETP with a CADV of 60,000, even though the Exchange is offering a smaller per share enhanced rebate, the total potential daily exposure ($270 per day) is significantly larger than the exposure in the ETP with the higher rebate, but smaller CADV. The Exchange notes, however, that there are some benefits associated with having BATS-listed ETPs with higher CADVs that, at a certain point, can more than offset the exposure from increased total rebate payments in such securities, as further described below. Because the Exchange faces greater exposure in enhanced rebates in ETPs with higher CADVs, the Exchange believes that it is reasonable to charge higher listing fees for ETPs with a higher CADV. Based on the foregoing, the Exchange believes that its proposed tiered pricing structure for the listing of ETPs is a fair and equitable allocation of fees to issuers.

The Exchange also believes that it is equitable, reasonable, and non-discriminatory to provide listings free of charge to ETPs with CADV exceeding 400,000. As a general matter, ETPs that are better known and well-established are frequently more actively traded, liquid securities. The Exchange believes that the benefits to both the Exchange and other Exchange constituents of attracting and retaining such ETPs to list on the Exchange justifies the Exchange waiving the listing fees for these issuers. As it relates to other issuers, the ability of the Exchange to attract well-known, recognizable, and successful ETPs on the Exchange will help the Exchange to establish its status and reputation as a

[7] 15 U.S.C. 78f.

[8] 15 U.S.C. 78f(b)(4) and (5).

primary listing market. The Exchange's reputation as a primary listing market will, in turn, positively impact all securities that are listed on the Exchange. Further, the Exchange believes that additional revenue generated from the Exchange's auction processes for actively traded ETPs will offset the cost of operating a program for these securities. Because ETPs with higher CADV are likely to generate additional revenue for the Exchange, the Exchange believes it is reasonable to waive fees for ETPs with CADV greater than 400,000. Based on the foregoing, the Exchange believes that providing annual listing free of charge for issuers of ETPs with CADV greater than 400,000 is a fair and equitable allocation of fees to issuers.

The Exchange believes it is reasonable and equitable to assess annual fees on a pro-rated quarterly basis instead of an annual basis based on the listing date of an ETP. In particular, the Exchange believes that quarterly billing in prorated amounts will allow an issuer's bill to more accurately reflect an ETP's current CADV.

The Exchange also believes that lowering the initial listing fee from $10,000 to $5,000 for ETPs is reasonable and equitable because it will result in lower initial costs to all ETP issuers.

Finally, the Exchange believes that correcting the typographical error to the numbering of the subparagraphs of Rule 14.13 is reasonable and equitable because it will make the rule text more easily understandable.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange 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, as amended. With respect to the proposed new pricing for the listing of ETPs, the Exchange does not believe that the changes burden competition, but instead, enhance competition, as it is intended to increase the competitiveness of the Exchange's listings program. The Exchange also believes the proposed change would enhance competition because it brings ETP listings prices closer to those currently offered by both Arca and Nasdaq. The proposed changes are generally intended to lower the Exchange's listing fees and make these fees more reflective of an ETP's trading activity, which the Exchange believes will further help it compete against the other listing markets. As such, the proposal is a competitive proposal that is intended to attract additional ETP listings, which will, in turn, benefit the Exchange and all other BATS-listed ETPs.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The Exchange has not solicited, and does not intend to solicit, comments on this proposed rule change. The Exchange has not received any written comments from members or other interested parties.

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[9] and paragraph (f) of Rule 19b–4 thereunder.[10] At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include File Number SR–BATS–2014–024 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–BATS–2014–024. 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 Web site (*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 Web site 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; the Commission does not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly. All submissions should refer to File Number SR–BATS–2014–024, and should be submitted on or before July 9, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[11]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–14232 Filed 6–17–14; 8:45 am]

BILLING CODE 8011–01–P

[9] 15 U.S.C. 78s(b)(3)(A)(ii).

[10] 17 CFR 240.19b–4(f).

[11] 17 CFR 200.30–3(a)(12).

SOCIAL SECURITY ADMINISTRATION

Agency Information Collection Activities: Comment Request

The Social Security Administration (SSA) publishes a list of information collection packages requiring clearance by the Office of Management and Budget (OMB) in compliance with Public Law 104–13, the Paperwork Reduction Act of 1995, effective October 1, 1995. This notice includes three revisions and one extension of OMB-approved information collections.

SSA is soliciting comments on the accuracy of the agency's burden estimate; the need for the information; its practical utility; ways to enhance its quality, utility, and clarity; and ways to minimize burden on respondents, including the use of automated collection techniques or other forms of information technology. Mail, email, or fax your comments and recommendations on the information collection(s) to the OMB Desk Officer and SSA Reports Clearance Officer at the following addresses or fax numbers.

(OMB), Office of Management and Budget, Attn: Desk Officer for SSA, Fax: 202–395–6974, Email address: *OIRA_Submission@omb.eop.gov/.*

(SSA), Social Security Administration, OLCA, Attn: Reports Clearance Director, 3100 West High Rise, 6401 Security Blvd., Baltimore, MD 21235, Fax: 410–966–2830, Email address: *OR.Reports.Clearance@ssa.gov*.

SSA submitted the information collections below to OMB for clearance. Your comments regarding the information collections would be most useful if OMB and SSA receive them 30 days from the date of this publication. To be sure we consider your comments, we must receive them no later than July 18, 2014. Individuals can obtain copies of the OMB clearance packages by writing to *OR.Reports.Clearance@ssa.gov.*

1. Representative Payee Report—Adult, Representative Payee Report—Child, Representative Payee Report—Organizational Representative Payees—20 CFR 404.635, 404.2035, 404.2065, and 416.665—0960–0068. When SSA determines it is not in an Old Age, Survivors, and Disability Insurance (OASDI) or Supplemental Security Income (SSI) recipient's best interest to receive Social Security payments directly, the agency will designate a representative payee for the recipient. The representative payee can be: (1) A family member; (2) a non-family member who is a private citizen and is acquainted with the beneficiary; (3) an organization; (4) a state or local government agency; or (5) a business. In the capacity of representative payee, the person or organization receives the SSA recipient's payments directly and manages these payments. As part of its stewardship mandate, SSA must ensure the representative payees are properly using the payments they receive for the recipients they represent. The agency annually collects the information necessary to make this assessment using the SSA–623, Representative Payee Report—Adult, SSA–6230, Representative Payee Report—Child, SSA–6234, Representative Payee Report—Organizational Representative Payees, and through the electronic internet application Internet Representative Payee Accounting (iRPA). The respondents are representative payees of OASDI and SSI recipients.

Type of Request: Revision to an OMB-approved information collection.

Modality of completion	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated total annual burden (hours)
SSA–623	2,811,819	1	15	702,955
SSA–6230	2,968,096	1	15	742,024
SSA–6234	719,469	1	15	179,867
iRPA *	650,000	1	15	162,500
Totals	7,149,384			1,787,346

* One Internet platform encompasses all three paper forms.

2. Statement of Income and Resources—20 CFR 416.207, 146.301–416.310, 416.704, and 416.708—0960–0124. SSA collects information about income and resources for SSI claims and redeterminations on the SSA–8010–BK. SSA uses the information to make initial or continuing eligibility determinations for SSI claimants or recipients who are subject to deeming. The respondents are persons whose income and resources SSA may deem (consider to be available) to SSI applicants or recipients.

Type of Request: Revision of an OMB-approved information collection.

Modality of completion	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated total annual burden (hours)
SSA–8010–BK	341,000	1	26	147,767

3. Authorization to Obtain Earnings Data From the Social Security Administration—0960–0602. On occasion, public and private organizations and agencies, need to obtain detailed earnings information about specific Social Security number (SSN) holding wage earners for business purposes (e.g. pension funds, State agencies, etc.). Respondents use Form SSA–581 to identify the SSN holder whose information they are requesting, and provide authorization from the SSN holder, when applicable. SSA uses the information provided on Form SSA–581 to: (1) Identify the wage earner; (2) establish the period of earnings information requested; (3) verify the wage earner authorized SSA to release this information to the requesting party; and (4) produce the Itemized Statement of Earnings (SSA–1826). The respondents are private businesses, state or local agencies, and other federal agencies.

Type of Request: Revision of an OMB-approved information collection.

Modality of completion	Number of respondents	Frequency of response	Average burden per response (minutes)	Estimated total annual burden (hours)
SSA–581	24,000	1	2	800

4. Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery—0960–0788. SSA, as part of our continuing effort to reduce paperwork and respondent burden, invites the general public to take this opportunity to comment on the ''Generic Clearance for the Collection of Qualitative Feedback on Agency Service Delivery '' for approval under the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 et. seq.). This collection was developed as part of a Federal Government-wide effort to streamline the process for seeking feedback from the public on service delivery.

Under the auspices of Executive Order 12862, Setting Customer Service Standards, SSA conducts multiple satisfaction surveys each year. This proposed information collection activity provides a means to garner qualitative customer and stakeholder feedback in an efficient, timely manner, in accordance with SSA's commitment to improving service delivery. By qualitative feedback we mean information that provides useful insights on perceptions and opinions, but are not statistical surveys that yield quantitative results that can be generalized to the population of study. This feedback will provide insights into customer or stakeholder perceptions, experiences and expectations, provide an early warning of issues with service, or focus attention on areas where communication, training or changes in operations might improve delivery of products or services. These collections will allow for ongoing, collaborative, and actionable communications between SSA and our customers and stakeholders.

The solicitation of feedback will target areas such as: Timeliness, appropriateness, accuracy of information, courtesy, efficiency of service delivery, and resolution of issues with service delivery. Responses will be assessed to plan and inform efforts to improve or maintain the quality of service offered to the public. If this information is not collected, vital feedback from customers and stakeholders on SSA's services will be unavailable.

We will only submit a collection for approval under this generic clearance if it meets the following conditions: (1) The collections are voluntary; (2) the collections are low-burden for respondents (based on considerations of total burden hours, total number of respondents, or burden-hours per respondent) and are low-cost for both the respondents and the Federal Government; (3) the collections are non-controversial and do not raise issues of concern to other Federal agencies; (4) any collection targeted to the solicitation of opinions from respondents who have experience with the program or may have experience with the program in the near future; (5) personally identifiable information (PII) is collected only to the extent necessary and is not retained; (6) information gathered will be used only internally for general service improvement and program management purposes and is not intended for release outside of the agency; (7) information gathered will not be used for the purpose of substantially informing influential policy decisions; and (8) information gathered will yield qualitative information; the collections will not be designed or expected to yield statistically reliable results or used as though the results are generalizable to the population of study.

Feedback collected under this generic clearance provides useful information, but it does not yield data that can be generalized to the overall population. This type of generic clearance for qualitative information will not be used for quantitative information collections that are designed to yield reliably actionable results, such as monitoring trends over time or documenting program performance. Such data uses require more rigorous designs that address the target population to which generalizations will be made, the sampling frame, the sample design (including stratification and clustering), the precision requirements or power calculations that justify the proposed sample size, the expected response rate, methods for assessing potential non-response bias, the protocols for data collection, and any testing procedures that were or will be undertaken prior to fielding the study. Depending on the degree of influence the results are likely to have, such collections may still be eligible for submission for other generic mechanisms that are designed to yield quantitative results.

As a general matter, information collections will not result in any new system of records containing privacy information and will not ask questions of a sensitive nature, such as sexual behavior and attitudes, religious beliefs, and other matters that are commonly considered private.

The respondents are recipients of SSA services (including most members of the public), professionals, and individuals who work on behalf of SSA beneficiaries.

Type of Request: Extension of an OMB-approved information collection.

Affected Public: Individuals and households, businesses and organizations, State, Local or Tribal government.

This is a correction notice: SSA published the incorrect burden information for this collection at 79 FR 17632, on 03/28/14. We are correcting this error here.

Total Estimated Number of Respondents: 46,530.

Below we provide projected average estimates for the next three years:

Average Expected Annual Number of activities: 125.

Annual Respondents: 15,510.

Annual Responses: 15,510.

Frequency of Response: Once per request.

Average minutes per response: 41.53 minutes.

Estimated Annual Burden: 10,581 hours.

Dated: June 13, 2014.

Faye Lipsky,

Reports Clearance Director, Social Security Administration.

[FR Doc. 2014–14207 Filed 6–17–14; 8:45 am]

BILLING CODE 4191–02–P

SOCIAL SECURITY ADMINISTRATION

[Docket No. SSA–2014–0023]

Agreement on Social Security Between the United States and the Slovak Republic; Entry Into Force

AGENCY: Social Security Administration (SSA).

ACTION: Notice.

SUMMARY: We are giving notice that an agreement coordinating the United States (U.S.) and the Slovak social security programs entered into force on May 1, 2014. The agreement with the Slovak Republic, which was signed on December 10, 2012, is similar to U.S. social security agreements already in force with 24 other countries—Australia, Austria, Belgium, Canada, Chile, the Czech Republic, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Japan, Korea (South), Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, Sweden, Switzerland and the United Kingdom. Section 233 of the Social Security Act authorizes agreements of this type. 42 U.S.C. 433.

SUPPLEMENTARY INFORMATION: Like the other agreements, the U.S.-Slovak agreement eliminates dual social security coverage. This situation exists when a worker from one country works in the other country and has coverage under the social security systems of both countries for the same work. Without such agreements in force, when

dual coverage occurs, the worker, the worker's employer, or both may be required to pay social security contributions to the two countries simultaneously. Under the U.S.-Slovak agreement, a worker who is sent by an employer in one country to work in the other country for 5 years or less remains covered only by the sending country. The agreement includes additional rules that eliminate dual U.S. and Slovak coverage in other work situations.

The agreement also helps eliminate situations where workers suffer a loss of benefit rights because they have divided their careers between the two countries. Under the agreement, workers may qualify for partial U.S. benefits or partial Slovak benefits based on combined (totalized) work credits from both countries.

If you want more information about the agreement's provisions, you may write to the Social Security Administration, Office of International Programs, Post Office Box 17741, Baltimore, MD 21235–7741 or visit the Social Security Web site at *www.socialsecurity.gov/international*. The full text of the agreement and its accompanying administrative arrangement is available at *www.socialsecurity.gov/international/Agreement_Texts/slovakrepublic.html.*

Dated: June 10, 2014.

Carolyn Colvin,

Acting Commissioner of Social Security.

[FR Doc. 2014–14217 Filed 6–17–14; 8:45 am]

BILLING CODE 4191–02–P

FEDERAL REGISTER

Vol. 79 Wednesday,

No. 117 June 18, 2014

Part II

Environmental Protection Agency

40 CFR Part 60

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2013–0602; FRL–9911–86–OAR]

RIN 2060–AR33

Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: In this action, the Environmental Protection Agency (EPA) is proposing emission guidelines for states to follow in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units. Specifically, the EPA is proposing state-specific rate-based goals for carbon dioxide emissions from the power sector, as well as guidelines for states to follow in developing plans to achieve the state-specific goals. This rule, as proposed, would continue progress already underway to reduce carbon dioxide emissions from existing fossil fuel-fired power plants in the United States.

DATES: *Comments on the proposed rule.* Comments must be received on or before October 16, 2014. *Comments on the information collection request.* Under the Paperwork Reduction Act (PRA), since the Office of Management and Budget (OMB) is required to make a decision concerning the information collection request between 30 and 60 days after June 18, 2014, a comment to the OMB is best assured of having its full effect if the OMB receives it by July 18, 2014.

Public Hearing. Four public hearings will be convened. On July 29, 2014, one public hearing will be held in Atlanta, Georgia, at the Sam Nunn Atlanta Federal Center Main Tower Bridge Conference Area, Conference Room B, 61 Forsyth Street SW., Atlanta, GA 30303, and one will be held in Denver, Colorado, at the EPA's Region 8 Building, 1595 Wynkoop Street, Denver, Colorado 80202. On July 30, 2014, a public hearing will be held in Washington, DC, at the William Jefferson Clinton East Building, Room 1152, 1201 Constitution Avenue NW., Washington, DC 20004. On July 31, 2014, a public hearing will be held in Pittsburgh, Pennsylvania at the William S. Moorhead Federal Building, Room 1310, 1000 Liberty Avenue, Pittsburgh, Pennsylvania 15222. The hearings in Pittsburgh, Pennsylvania, Atlanta, Georgia, and Washington, DC, will convene at 9:00 a.m. and end at 8:00 p.m. (Eastern Standard Time). The hearing in Denver, Colorado, will convene at 9:00 a.m. and end at 8:00 p.m. (Mountain Daylight Time). For all hearings there will be a lunch break from 12:00 p.m. to 1:00 p.m. and a dinner break from 5:00 p.m. to 6:00 p.m. Please contact Ms. Pamela Garrett at 919–541–7966 or at *garrett.pamela@epa.gov* to register to speak at one of the hearings. The last day to pre-register in advance to speak at the hearings will be Friday, July 25, 2014. Additionally, requests to speak will be taken the day of the hearings at the hearing registration desk, although preferences on speaking times may not be able to be fulfilled. If you require the service of a translator or special accommodations such as audio description, please let us know at the time of registration.

The hearings will provide interested parties the opportunity to present data, views or arguments concerning the proposed action. The EPA will make every effort to accommodate all speakers who arrive and register. Because these hearings are being held at U.S. government facilities, individuals planning to attend the hearing should be prepared to show valid picture identification to the security staff in order to gain access to the meeting room. Please note that the REAL ID Act, passed by Congress in 2005, established new requirements for entering federal facilities. These requirements will take effect July 21, 2014. If your driver's license is issued by Alaska, American Samoa, Arizona, Kentucky, Louisiana, Maine, Massachusetts, Minnesota, Montana, New York, Oklahoma, or the state of Washington, you must present an additional form of identification to enter the federal buildings where the public hearings will be held. Acceptable alternative forms of identification include: Federal employee badges, passports, enhanced driver's licenses and military identification cards. We will list any additional acceptable forms of identification at: *http://www2.epa.gov/cleanpowerplan/*. In addition, you will need to obtain a property pass for any personal belongings you bring with you. Upon leaving the building, you will be required to return this property pass to the security desk. No large signs will be allowed in the building, cameras may only be used outside of the building and demonstrations will not be allowed on federal property for security reasons.

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 comments and supporting information presented at the public hearing. Commenters should notify Ms. Garrett if they will need specific equipment, or if there are other special needs related to providing comments at the hearings. Verbatim transcripts of the hearings and written statements will be included in the docket for the rulemaking. 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. Additionally, more information regarding the hearings will be available at: *http://www2.epa.gov/cleanpowerplan/.*

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2013–0602, by one of the following methods:

Federal eRulemaking portal: http://www.regulations.gov. Follow the online instructions for submitting comments.

Email: A-and-R-Docket@epa.gov. Include docket ID No. EPA–HQ–OAR–2013–0602 in the subject line of the message.

Facsimile: (202) 566–9744. Include docket ID No. EPA–HQ–OAR–2013–0602 on the cover page.

Mail: Environmental Protection Agency, EPA Docket Center (EPA/DC), Mail code 28221T, Attn: Docket ID No. EPA–HQ–OAR–2013–0602, 1200 Pennsylvania Ave. NW., Washington, DC 20460. In addition, please mail a copy of your comments on the information collection provisions to the Office of Information and Regulatory Affairs, OMB, Attn: Desk Officer for the EPA, 725 17th St. NW., Washington, DC 20503.

Hand/Courier Delivery: EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Ave. NW., Washington, DC 20004, Attn: Docket ID No. EPA–HQ–OAR–2013–0602. Such deliveries are accepted only during the Docket Center's normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding federal holidays), and special arrangements should be made for deliveries of boxed information.

Instructions: All submissions must include the agency name and docket ID number (EPA–HQ–OAR–2013–0602). The EPA's policy is to include all comments received without change, including any personal information provided, in the public docket, available online at *http://www.regulations.gov*, unless the comment includes information claimed to be Confidential

Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. Send or deliver information identified as CBI only to the following address: Mr. Roberto Morales, OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2013–0602. Clearly mark the part or all of the information that you claim to be CBI. For CBI information on a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information you claim as CBI. In addition to one complete version of the comment that includes information claimed as CBI, you must submit a copy of the comment that does not contain the information claimed as CBI for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR Part 2.

The EPA requests that you also submit a separate copy of your comments to the contact person identified below (see **FOR FURTHER INFORMATION CONTACT**). If the comment includes information you consider to be CBI or otherwise protected, you should send a copy of the comment that does not contain the information claimed as CBI or otherwise protected.

The *www.regulations.gov* Web site is an ''anonymous access'' system, 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 *http://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 disk or CD–ROM 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 avoid the use of special characters, any form of encryption and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *http://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 either electronically in *http://www.regulations.gov* or in hard copy at the EPA Docket Center, William Jefferson Clinton Building West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding federal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742. Visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm* for additional information about the EPA's public docket.

In addition to being available in the docket, an electronic copy of this proposed rule will be available on the Worldwide Web (WWW). Following signature, a copy of this proposed rule will be posted at the following address: *http://www2.epa.gov/cleanpowerplan/*.

FOR FURTHER INFORMATION CONTACT: Ms. Amy Vasu, Sector Policies and Programs Division (D205–01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541–0107, facsimile number (919) 541–4991; email address: *vasu.amy@epa.gov* or Ms. Marguerite McLamb, Sector Policies and Programs Division (D205–01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919) 541–7858, facsimile number (919) 541–4991; email address: *mclamb.marguerite@epa.gov*.

SUPPLEMENTARY INFORMATION:

Acronyms. A number of acronyms and chemical symbols are used in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined as follows:

ACEEE American Council for an Energy Efficient Economy
AEO Annual Energy Outlook
AFL–CIO American Federation of Labor and Congress of Industrial Organizations
ASTM American Society for Testing of Materials
BSER Best System of Emission Reduction
Btu/kWh British Thermal Units per Kilowatt-hour
CAA Clean Air Act
CBI Confidential Business Information
CCS Carbon Capture and Storage (or Sequestration)
CEMS Continuous Emissions Monitoring System
CHP Combined Heat and Power
CO_2 Carbon Dioxide
DOE Department of Energy
ECMPS Emissions Collection and Monitoring Plan System
EERS Energy Efficiency Resource Standard
EGU Electric Generating Unit
EIA Energy Information Administration
EM&V Evaluation, Measurement and Verification
EO Executive Order
EPA Environmental Protection Agency
FR **Federal Register**
GHG Greenhouse Gas
GW Gigawatt
HAP Hazardous Air Pollutant
HRSG Heat Recovery Steam Generator
IGCC Integrated Gasification Combined Cycle
IPCC Intergovernmental Panel on Climate Change
IPM Integrated Planning Model
IRP Integrated Resource Plan
ISO Independent System Operator
kW Kilowatt
kWh Kilowatt-hour
lb CO_2/MWh Pounds of CO_2 per Megawatt-hour
LBNL Lawrence Berkeley National Laboratory
MMBtu Million British Thermal Units
MW Megawatt
MWh Megawatt-hour
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System Commissioners
NAS National Academy of Sciences
NGCC Natural Gas Combined Cycle
NO_X Nitrogen Oxides
NRC National Research Council
NSPS New Source Performance Standard
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
NYSERDA New York State Energy Research and Development Authority
OMB Office of Management and Budget
PM Particulate Matter
$PM_{2.5}$ Fine Particulate Matter
PRA Paperwork Reduction Act
PSB Public Service Board
PUC Public Utilities Commission
REC Renewable Energy Credit
RES Renewable Energy Standard
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
RIA Regulatory Impact Analysis
RPS Renewable Portfolio Standard
RTO Regional Transmission Operator
SBA Small Business Administration
SBC System Benefits Charge
SCC Social Cost of Carbon
SIP State Implementation Plan
SO_2 Sulfur Dioxide
Tg Teragram (one trillion (10^{12}) grams)
TSD Technical Support Document
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act of 1995
UNFCCC United Nations Framework Convention on Climate Change
USGCRP U.S. Global Change Research Program
VCS Voluntary Consensus Standard

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I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

Under the authority of Clean Air Act (CAA) section 111(d), the EPA is proposing emission guidelines for states to follow in developing plans to address greenhouse gas (GHG) emissions from existing fossil fuel-fired electric generating units (EGUs). In this summary, we outline the proposal; discuss its purpose; summarize its major provisions, including the EPA's approach to determining goals; describe the broad range of options available to states, including flexibility in timing requirements both for plan submission and compliance deadlines under those plans; and briefly describe the estimated CO_2 emission reductions, costs and benefits expected to result from full implementation of the proposal.

This rule, as proposed, would continue progress already underway to lower the carbon intensity of power generation in the United States (U.S.). Lower carbon intensity means fewer emissions of CO_2, a potent greenhouse gas that contributes to climate change. This proposal is a significant step forward in the EPA and states partnering to reduce GHG emissions in the U.S. The proposal incorporates critical elements that reflect the information and views shared during the unprecedented effort that the EPA has undertaken, beginning in the summer of 2013, to interact directly with, and solicit input from, a wide range of states and stakeholders. This effort encompassed several hundred meetings across the country with state environmental and energy officials, public utility commissioners, system operators, utilities and public interest advocates, as well as members of the public. Many participants submitted written material and data to the EPA as well.

Nationwide, by 2030, this rule would achieve CO_2 emission reductions from the power sector of approximately 30 percent from CO_2 emission levels in 2005. This goal is achievable because innovations in the production, distribution and use of electricity are already making the power sector more efficient and sustainable while maintaining an affordable, reliable and diverse energy mix. This proposed rule would reinforce and continue this progress. The EPA projects that, in 2030, the significant reductions in the harmful carbon pollution and in other air pollution, to which this rule would lead, would result in net climate and health benefits of $48 billion to $82 billion. At the same time, coal and natural gas would remain the two leading sources of electricity generation in the U.S., with each providing more than 30 percent of the projected generation.

Based on evidence from programs already being implemented by many states as well as input received from stakeholders, the agency recognizes that the most cost-effective system of emission reduction for GHG emissions from the power sector under CAA section 111(d) entails not only improving the efficiency of fossil fuel-fired EGUs, but also addressing their utilization by taking advantage of opportunities for lower-emitting generation and reduced electricity demand across the electricity system's interconnecting network or grid.

The proposed guidelines are based on and would reinforce the actions already being taken by states and utilities to upgrade aging electricity infrastructure with 21st century technologies. The guidelines would ensure that these trends continue in ways that are consistent with the long-term planning and investment processes already used in this sector, to meet both region- and state-specific needs. The proposal provides flexibility for states to build upon their progress, and the progress of cities and towns, in addressing GHGs. It also allows states to pursue policies to reduce carbon pollution that: (1)

Continue to rely on a diverse set of energy resources, (2) ensure electric system reliability, (3) provide affordable electricity, (4) recognize investments that states and power companies are already making, and (5) can be tailored to meet the specific energy, environmental and economic needs and goals of each state. Thus, the proposed guidelines would achieve meaningful CO_2 emission reduction while maintaining the reliability and affordability of electricity in the U.S.

a. Proposal Elements

The proposal has two main elements: (1) State-specific emission rate-based CO_2 goals and (2) guidelines for the development, submission and implementation of state plans. To set the state-specific CO_2 goals, the EPA analyzed the practical and affordable strategies that states and utilities are already using to lower carbon pollution from the power sector. These strategies include improvements in efficiency at carbon-intensive power plants, programs that enhance the dispatch priority of, and spur private investments in, low emitting and renewable power sources, as well as programs that help homes and businesses use electricity more efficiently. In addition, in calculating each state's CO_2 goal, the EPA took into consideration the state's fuel mix, its electricity market and numerous other factors. Thus, each state's goal reflects its unique conditions.

While this proposal lays out state-specific CO_2 goals that each state is required to meet, it does not prescribe how a state should meet its goal. CAA section 111(d) creates a partnership between the EPA and the states under which the EPA sets these goals and the states take the lead on meeting them by creating plans that are consistent with the EPA guidelines. Each state will have the flexibility to design a program to meet its goal in a manner that reflects its particular circumstances and energy and environmental policy objectives. Each state can do so alone or can collaborate with other states on multi-state plans that may provide additional opportunities for cost savings and flexibility.

To facilitate the state planning process, this proposal lays out guidelines for the development and implementation of state plans. The proposal describes the components of a state plan, the latitude states have in developing compliance strategies, the flexibility they have in the timing for submittal of their plans and the flexibility they have in determining the schedule by which their sources must achieve the required CO_2 reductions. The EPA recognizes that each state has differing policy considerations—including varying emission reduction opportunities and existing state programs and measures—and that the characteristics of the electricity system in each state (e.g., utility regulatory structure, generation mix and electricity demand) also differ. Therefore, the proposed guidelines provide states with options for meeting the state-specific goals established by the EPA in a manner that accommodates a diverse range of state approaches. This proposal also gives states considerable flexibility with respect to the timeframes for plan development and implementation, providing up to two or three years for submission of final plans and providing up to fifteen years for full implementation of all emission reduction measures, after the proposal is finalized.

Addressing a concern raised by both utilities and states, the EPA is proposing that states could choose approaches in their compliance plans under which full responsibility for actions achieving reductions is not placed entirely upon emitting EGUs; instead, state plans could include measures and policies (e.g., demand-side energy efficiency programs and renewable portfolio standards) for which the state itself is responsible. Of course, individual states would also have the option of structuring programs (e.g., allowance-trading programs) under which full responsibility rests on the affected EGUs.

The EPA believes that, using the flexibilities inherent in CAA section 111(d), this proposal would result in significant reductions of GHG emissions that cause harmful climate change, while providing states with ample opportunity to design plans that use innovative, cost-effective strategies that take advantage of investments already being made in programs and measures that lower the carbon intensity of the power sector and reduce GHG emissions.

b. Policy Context and Industry Conditions

This proposal is an important step toward achieving the GHG emission reductions needed to address the serious threat of climate change. GHG pollution threatens the American public by leading to potentially rapid, damaging and long-lasting changes in our climate that can have a range of severe negative effects on human health and the environment. CO_2 is the primary GHG pollutant, accounting for nearly three-quarters of global GHG emissions [1] and 82 percent of U.S. GHG emissions.[2] The May 2014 report of the National Climate Assessment [3] concluded that climate change impacts are already manifesting themselves and imposing losses and costs. The report documents increases in extreme weather and climate events in recent decades, damage and disruption to infrastructure and agriculture, and projects continued increases in impacts across a wide range of communities, sectors, and ecosystems.

The President's Climate Action Plan,[4] issued in June 2013, recognizes that climate change has far-reaching harmful consequences and real economic costs. The Climate Action Plan details a broad array of actions to reduce GHG emissions that contribute to climate change and affect public health and the environment. One of the plan's goals is to reduce CO_2 emissions from power plants. This is because fossil fuel-fired EGUs are, by far, the largest emitters of GHGs, primarily in the form of CO_2, among stationary sources in the U.S. To accomplish this goal, President Obama issued a Presidential Memorandum [5] that recognized the importance of significant and prompt action. The Memorandum directed the EPA to complete carbon pollution standards, regulations or guidelines, as appropriate, for modified, reconstructed and existing power plants by June 1, 2015, and in doing so to build on state leadership in moving toward a cleaner power sector.

The way that power is produced, distributed and used is already changing due to advancements in innovative power sector technologies and in the availability and cost of low carbon fuel, renewable energy and energy efficient demand-side technologies, as well as economic conditions. In addition, the average age of the coal-fired generating fleet is increasing. In 2025, the average age of the coal-fired generating fleet is

[1] Intergovernmental Panel on Climate Change (IPCC) report, ''Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change,'' 2007. Available at *http://epa.gov/climatechange/ghgemissions/global.html.*

[2] Table ES–2 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[3] U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment, May 2014. Available at *http://nca2014.globalchange.gov/.*

[4] The President's Climate Action Plan, June 2013. *http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.*

[5] Presidential Memorandum—Power Sector Carbon Pollution Standards, June 25, 2013. *http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.*

projected to be 49 years old, and 20 percent of units would be more than 60 years old if they remained in operation at that time. Therefore, even in the absence of additional environmental regulation, states and utilities can be expected to be, and already are, making plans to address the changes necessitated by the aging of current assets and infrastructure. With change inevitably underway between now and 2030, a CAA section 111(d) rulemaking for CO_2 emissions is timely and can inform current and ongoing decision making by states and utilities, as well as private sector business and technology investments. As states develop their plans, they will make key decisions that will stimulate private sector investment and innovation associated with reducing GHG emissions. We expect that many states will consider the opportunities offered for their respective economies as a result of this investment.

The proposed guidelines are designed to build on and reinforce progress by states, cities and towns, and companies on a growing variety of sustainable strategies to reduce power sector CO_2 emissions. At the same time, the EPA believes that this proposal provides flexibility for states to develop plans that align with their unique circumstances, as well as their other environmental policy, energy and economic goals. All states will have the opportunity to shape their plans as they believe appropriate for meeting the proposed CO_2 goals. This includes states with long-established reliance on coal-fired generation, as well as states with a commitment to promoting renewable energy (including through sustainable forestry initiatives). It also includes states that are already participating in or implementing CO_2 reduction programs, such as the Regional Greenhouse Gas Initiative (RGGI), California's ''Global Warming Solutions Act'' and Colorado's ''Clean Air, Clean Jobs Act''.

States would be able to rely on and extend programs they may already have created to address the power sector. Those states committed to Integrated Resource Planning (IRP) would be able to establish their CO_2 reduction plans within that framework, while states with a more deregulated power sector system could develop CO_2 reduction plans within that specific framework. Each state, including states without an existing program, would have the opportunity to take advantage of a wide variety of strategies for reducing CO_2 emissions from affected EGUs. The EPA and other federal entities, including the U.S. Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC) and the U.S. Department of Agriculture, among others, are committed to sharing expertise with interested states as they develop and implement their plans.

States would be able to address the economic interests of their utilities and ratepayers by using the flexibilities in this proposed action to: (1) Reduce costs to consumers, minimize stranded assets, and spur private investments in renewable energy and energy efficiency technologies and businesses; and (2) if they choose, work with other states on multi-state approaches that reflect the regional structure of electricity operating systems that exists in most parts of the country and is critical to ensuring a reliable supply of affordable energy. The proposed rule gives states the flexibility to provide a broad range of compliance options that recognize that the power sector is made up of a diverse range of companies that own and operate fossil fuel-fired EGUs, including vertically integrated companies in regulated markets, independent power producers, rural cooperatives and municipally-owned utilities, all of which are likely to have different ranges of opportunities to reduce GHG emissions while facing different challenges in meeting these reductions.

Both existing state programs (such as RGGI, the California Global Warming Solutions Act program and the Colorado Clean Air, Clean Jobs Act program) and ideas suggested by stakeholders show that there are a number of different ways that states can design programs that achieve required reductions while working within existing market mechanisms used to dispatch power effectively in the short term and to ensure adequate capacity in the long term. These programs and programs for conventional pollutants, such as the Acid Rain Program under Title IV of the CAA, have demonstrated that compliance with environmental programs can be monetized such that it is factored into power sector economic decision making in ways that reduce the cost of controlling pollution, maintain electricity system reliability and work within the least cost dispatching principles that are key to operation of our electric power grid. The proposal would also allow states to work together with individual companies on potential specific challenges. These and other flexibilities are discussed further in Section VIII of the preamble.

a. CAA Section 111(d) Requirements

Under CAA section 111(d),[6] state plans must establish standards of performance that reflect the degree of emission limitation achievable through the application of the ''best system of emission reduction'' that, taking into account the cost of achieving such reduction and any non-air quality health and environmental impacts and energy requirements, the Administrator determines has been adequately demonstrated (BSER).[7] Consistent with CAA section 111(d), the EPA is proposing state-specific goals that reflect the EPA's calculation of the emission limitation that each state can achieve through the application of the BSER. This calculation reflects the degree of emission limitation that the state plan must achieve in order to implement the BSER that the EPA has determined has been adequately demonstrated and that, in turn, would be required to be, and via the calculation, has been, applied for the affected EGUs in each state. A CAA section 111(d) state plan will differ from a state implementation plan (SIP) for a criteria air pollutant national ambient air quality standard (NAAQS) in several respects, reflecting the significant differences between CAA sections 110 and 111. A CAA section 110 SIP must be designed to meet the NAAQS for a criteria air pollutant for a particular area—not for a source category—within a timeframe specified in the CAA. The NAAQS itself is based on the current body of scientific evidence and, by law, does not reflect consideration of cost. By contrast, a CAA section 111(d) state plan must be designed to achieve a specific level of emission performance that has been established for a particular source category within a timeframe determined by the Administrator and, to some extent, by each state. Moreover, the emission levels for the source category reflect a determination of the BSER, which incorporates consideration of cost, technical feasibility and other factors.

To determine the BSER for reducing CO_2 emissions at affected EGUs, the EPA considered numerous measures that are already being implemented and can be implemented more broadly to

[6] See also 40 CFR 60.22(b)(5).

[7] Under CAA section 111(a)(1) and (d), the EPA is authorized to determine the BSER and to calculate the amount of emission reduction achievable through applying the BSER. The state is authorized to identify the standard or standards of performance that reflects that amount of emission reduction. In addition, the state is required to include in its state plan the standards of performance and measures to implement and enforce those standards. The state must submit the plan to the EPA, and the EPA must approve the plan if the standards of performance and implementing and enforcing measures are satisfactory. This is discussed in more detail in Sections IV, VI, VII and VIII of this preamble, as well as in the Legal Memorandum.

improve emission rates and to reduce overall CO_2 emissions from fossil fuel-fired EGUs. Overall, the BSER proposed here is based on a range of measures that fall into four main categories, or ''building blocks,'' which comprise improved operations at EGUs, dispatching lower-emitting EGUs and zero-emitting energy sources, and end-use energy efficiency. All of these measures have been amply demonstrated via their current widespread use by utilities and states.

The proposed guidelines are structured so that states would not be required to use each and every one of the measures that the EPA determines constitute the BSER or to apply any one of those measures to the same extent that the EPA determines is achievable at reasonable cost. Instead, in developing its plan, each state will have the flexibility to select the measure or combination of measures it prefers in order to achieve its CO_2 emission reduction goal. Thus, a state could choose to achieve more reductions from one measure encompassed by the BSER and less from another, or it could choose to include measures that were not part of the EPA's BSER determination, as long as the state achieves the CO_2 reductions at affected EGUs necessary to meet the goal that the EPA has defined as representing the BSER.

As explained in further detail in Sections VI, VII and VIII of this preamble regarding the agency's determination of the BSER, the EPA is offering the opportunity via this proposal to comment on the proposed BSER, the proposed methodology for computing state goals based on application of the BSER, and the state-specific data used in the computations. Once the final goals have been promulgated, a state would no longer have an opportunity to request that the EPA adjust its CO_2 goal. The final state-specific CO_2 goals would reflect any adjustments as appropriate based on comments provided to the EPA to address any data errors in the analysis for the proposed goals. We expect that states will be able to meet the CO_2 goals because they will represent the application of the BSER for the states' affected sources.

This proposed rule sets forth the state goals that reflect the BSER and guidelines for states to use in developing their plans to reduce CO_2 from fossil fuel-fired EGUs. The preamble describes the proposed expectations for state plans and discusses options that the EPA has considered. It also explains the EPA's authority to define the BSER, as well as state goals, and each state's responsibility to develop and implement standards of performance that will achieve its CO_2 goal. Additional detail on various aspects of the proposal is included in several technical support documents (TSDs) and memoranda, which are available in the rulemaking docket.

The proposal was substantially informed by the extensive input from states and a wide range of stakeholders that the EPA sought and has received since the summer of 2013. The EPA invites further input through public comment on all aspects of this proposal.

2. Summary of the Proposal's Major Provisions

a. Approach

In developing this proposed rulemaking, the EPA is implementing statutory provisions that have been in place since Congress first enacted the CAA in 1970 and that have been implemented pursuant to regulations promulgated in 1975 and followed in subsequent CAA section 111(d) rulemakings. These provisions ensure that, in concert with the provisions of CAA sections 110 and 112, new and existing major stationary sources operate in ways that address their emissions of significant air pollutants that are harmful to public health and the environment. These requirements call on the EPA to develop emission guidelines, which reflect the EPA's determination of the BSER, for states to follow in formulating compliance plans to implement standards of performance to achieve emission reductions consistent with the BSER. In following these provisions, the EPA is proposing a BSER based on strategies currently being used by states and companies to reduce CO_2 emissions from EGUs.

The CAA, as interpreted by the courts, identifies several factors for the EPA to consider in a BSER determination. These include technical feasibility, costs, size of emission reductions and technology (e.g., whether the system promotes the implementation and further development of technology). In determining the BSER, the EPA considered the reductions achievable through measures that reduce CO_2 emissions from existing fossil fuel-fired EGUs either by (1) reducing the CO_2 emission rate at those units or (2) reducing the units' CO_2 emission total to the extent that generation can be shifted from higher-emitting fossil fuel-fired EGUs to lower- or zero-emitting options.

As the EPA has done in making BSER determinations in previous CAA section 111(d) rulemakings, the agency considered the types of strategies that states and owners and operators of EGUs are already employing to reduce the covered pollutant (in this case, CO_2) from affected sources (in this case, fossil fuel-fired EGUs).[8] Across the nation, many states, cities and towns, and owners and operators of EGUs have shown leadership in creating and implementing policies and programs that reduce CO_2 emissions from the power sector while achieving other economic, environmental and energy benefits. Some of these activities, such as market-based programs and GHG performance standards, directly require CO_2 emission reductions from EGUs. Others reduce CO_2 emissions by reducing utilization of fossil fuel-fired EGUs through, for example, renewable portfolio standards (RPS) and energy efficiency resource standards (EERS). For example, currently 10 states have market-based GHG emission programs, 38 states have renewable portfolio standards or goals, and utilities in 47 states run demand-side energy efficiency programs. Many individual companies also have significant voluntary CO_2 emission reduction programs.

Such strategies—and the proposed BSER determination—reflect the fact that, in almost all states, the production, distribution and use of electricity can be, and is, undertaken in ways that accommodate reductions in both pollution emission rates and total emissions. Specifically, electricity production, at least to some extent, takes place interchangeably between and among multiple generation facilities and different types of generation, a fact that Congress, the EPA and the states have long relied on in enacting or promulgating pollution reduction programs, such as Title IV of the CAA, the NO_X SIP Call, the Cross State Air Pollution Rule (CSAPR) and RGGI.

As a result, the agency, in quantifying state goals, assessed what combination of electricity production or energy demand reduction across generation facilities can offer a reasonable-cost, technically feasible approach to achieving CO_2 emission reductions. States, in turn, will be able to look broadly at opportunities across their

[8] The final emission guidelines for landfill gas emissions from municipal solid waste landfills, published on March 12, 1996 and amended on June 16, 1998 (61 FR 9905 and 63 FR 32743, respectively) are one example, as they allow either of two approaches for controlling landfill gas—by recovering the gas as a fuel, for sale, and removing from the premises, or by destroying the organic content of the gas on the premises using a control device. Recovering the gas as a fuel source was a practice already being used by some affected sources prior to promulgation of the rulemaking.

electricity system in devising plans to meet their goals. Importantly, states may rely on measures that they already have in place, including renewable energy standards and demand-side energy efficiency programs, and the proposal details how such existing state programs can be incorporated into state plans. States will also be able to participate in multi-state programs that already exist or may create new ones.

Thus, to determine the BSER for reducing CO_2 emissions at affected EGUs and to establish the numerical goals that reflect the BSER, the EPA considered numerous measures that can and are being implemented to improve emission rates and to reduce or limit mass CO_2 emissions from fossil fuel-fired EGUs. These measures encompass two basic approaches: (1) Reducing the carbon intensity of certain affected EGUs by improving the efficiency of their operations, and (2) addressing affected EGUs' mass emissions by varying their utilization levels. For purposes of expressing the BSER as an emission limitation, in this case in the form of state-level goals, we propose to base these two approaches on measures grouped into four main categories, or ''building blocks.'' These building blocks can also be used as a guide to states for constructing broad-based, cost-effective, long-term strategies to reduce CO_2 emissions. The EPA believes that the application of measures from each of the building blocks can achieve CO_2 emission reductions at fossil fuel-fired EGUs such that, when combined with measures from other building blocks, the measures represent the ''best system of emission reduction . . . adequately demonstrated'' for fossil fuel-fired EGUs. The building blocks are:

1. Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements.
2. Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including NGCC units under construction).
3. Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.
4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

The four building blocks are described in detail in Sections VI of this preamble. As explained in that section, the EPA evaluated each of the building blocks individually against the BSER criteria and found that each of the building blocks independently merits consideration as part of the BSER. The EPA also evaluated combinations of the building blocks against the BSER criteria—in particular, a combination of all four building blocks and a combination of building blocks 1 and 2.

Based on that evaluation, the EPA proposes that the combination of all four building blocks is the BSER. The combination of all four blocks best represents the BSER because it achieves greater emission reductions at a lower cost, takes better advantage of the wide range of measures that states, cities, towns and utilities are already using to reduce CO_2 from EGUs and reflects the integrated nature of the electricity system and the diversity of electricity generation technology. Section VI of this preamble also explains how the EPA considered more aggressive application of measures in each block. This includes consideration of more extensive application of measures that the EPA determined do represent a component of the BSER (such as more extensive or accelerated application of demand-side measures), as well as consideration of options in some blocks that the EPA determined would not represent the BSER for existing sources (such as the inclusion of retrofit carbon capture and storage or sequestration (CCS) on existing EGUs).

As part of the BSER determination, the EPA considered the impacts that implementation of the emission reductions based on the combination of the blocks would have on the cost of electricity and electricity system reliability. As the preamble details, the EPA believes that, both with respect to the overall proposed BSER and with respect to the individual building blocks, the associated costs are reasonable. Importantly, the proposed BSER, expressed as a numeric goal for each state, provides states with the flexibility to determine how to achieve the reductions (i.e., greater reductions from one building block and less from another) and to adjust the timing in which reductions are achieved, in order to address key issues such as cost to consumers, electricity system reliability and the remaining useful life of existing generation assets.

In sum, the EPA proposes that the BSER for purposes of CAA section 111(d), as applied to existing fossil fuel-fired EGUs, is based on a combination of measures that reduce CO_2 emissions and CO_2 emission rates and encompass all four building blocks.[9] We are also soliciting comment on application of only the first two building blocks as the basis for the BSER, while noting that application of only the first two building blocks achieves fewer CO_2 reductions at a higher cost.

In determining the BSER, we have considered the ranges of reductions that can be achieved by application of each building block, and we have identified goals that we believe reflect a reasonable degree of application of each building block consistent with the BSER criteria. Relying on all four building blocks to characterize the combination of measures that reduce CO_2 emissions and CO_2 emission rates at affected EGUs as the basis for the BSER is consistent with strategies, actions and measures that companies and states are already undertaking to reduce GHG emissions and with current trends in the electric power sector, driven by efforts to reduce GHGs as well as by other factors, such as advancements in technology. Reliance on all four building blocks in this way also supports the goals of achieving significant and technically feasible reductions of CO_2 at a reasonable cost, while also promoting technology and approaches that are important for achieving further reductions. Finally, the EPA believes that the diverse range of measures encompassed in the four building blocks allows states and sources to take full advantage of the inherent flexibility of the current regionally interconnected and integrated electricity system so as to achieve the CO_2 goals while continuing to meet the demand for electricity services in a reliable and affordable manner.

The EPA recognizes that states differ in important ways, including in their mix of existing EGUs and in their policy priorities. Consequently, opportunities and preferences for reducing emissions, as reflected in each of the building blocks, vary across states. While the state-specific goals that the EPA is proposing in this rule are based on consistent application of a single goal-setting methodology across all states, the goals account for these key differences. The state-specific CO_2 goals derived from application of the methodology vary because, in setting the goals for a state, the EPA used data specific to each state's EGUs and certain

[9] The EPA notes that under the proposed BSER, some building blocks would apply to some, but not all, affected sources. Specifically, building block 1 would apply to affected coal-fired steam EGUs, building block 2 would apply to all affected steam EGUs (both coal-fired and oil/gas-fired), and building blocks 3 and 4 would apply to all affected EGUs.

other attributes of its electricity system (e.g., current mix of generation resources).

The proposed BSER and goal-setting methodology reflect information provided and priorities expressed during the EPA's recent, extensive public outreach process. The input we received ranged from the states' desires for flexibility and recognition of varying state circumstances to the success that states and companies have had in adopting a range of pollution—and demand-reduction strategies. The state-specific approach embodied in both CAA section 111(d) and this proposal recognizes that ultimately states are the most knowledgeable about their specific circumstances and are best positioned to evaluate and leverage existing and new generation capacity and programs to reduce CO_2 emissions.

To meet its goal, each state will be able to design programs that use the measures it selects, and these may include the combination of building blocks most relevant to its specific circumstances and policy preferences. States may also identify technologies or strategies that are not explicitly mentioned in any of the four building blocks and may use those technologies or strategies as part of their overall plans (e.g., market-based trading programs or construction of new natural combined cycle units or nuclear plants). Further, the EPA's approach allows multi-state compliance strategies.

The agency also recognizes the important functional relationship between the period of time over which measures are deployed and the stringency of emission limitations those measures can achieve in a practical and reasonable cost way. Because, for this proposal, the EPA is proposing a 10-year period over which to achieve the full required CO_2 reductions, a period that begins more than five years from the date of this proposal, a state could take advantage of this relationship in the design of its program by using relevant combinations of building blocks to achieve its state goal in a manner that provides for electricity system reliability, avoids the creation of stranded assets and has a reasonable cost.

b. State Goals and Flexibilities

In this action, the EPA is proposing state-specific rate-based goals that state plans must be designed to meet. These state-specific goals are based on an assessment of the amount of emissions that can be reduced at existing fossil fuel-fired EGUs through application of the BSER, as required under CAA section 111(d). The agency is proposing state-specific final goals that must be achieved by no later than the year 2030. The proposed final goals reflect the EPA's quantification of adjusted state-average emission rates from affected EGUs that could be achieved at reasonable cost by 2030 through implementation of the four building blocks described above.

The EPA recognizes that, with many measures, states can achieve emission reductions in the short-term, though the full effects of implementation of other measures, such as demand-side energy efficiency (EE) programs and the addition of renewable energy (RE) generating capacity, can take longer. Thus, the EPA is proposing interim goals that states must meet beginning in 2020. The proposed interim goals would apply over a 2020–2029 phase-in period. They reflect the level of reductions in CO_2 emissions and emission rates and the extent of the application of the building blocks that would be presumptively approvable in a state plan during the ramp-up to achieving the final goal.

The EPA is proposing to allow each state flexibility with regard to the form of the goal. A state could adopt the rate-based form of the goal established by the EPA or an equivalent mass-based form of the goal. A multi-state approach incorporating either a rate- or mass-based goal would also be approvable based upon a demonstration that the state's plan would achieve the equivalent in stringency, including compliance timing, to the state-specific rate-based goal set by the EPA.

We believe that this approach to establishing requirements for states in developing their plans responds both to the needs of an effectively implemented program and to the range of viewpoints expressed by stakeholders regarding the simultaneous need for both flexibility and clear guidance on what would constitute an approvable state plan. We likewise believe that this approach represents a reasonable balance between two competing objectives grounded in CAA section 111(d)—a need for rigor and consistency in calculating emission reductions reflecting the BSER and a need to provide the states with flexibility in establishing and implementing the standards of performance that reflect those emission reductions. The importance of this balance is heightened by the fact that the operations of the electricity system itself rely on the flexibility made available and achieved through dispatching between and among multiple interconnected EGUs, demand management and end-use energy efficiency. We view the proposed goals as providing rigor where required by the statute with respect to the amount of emission reductions, while providing states with flexibility where permitted by the statute, particularly with respect to the range of measures that a state could include in its plan. This approach recognizes that state plans for emission reductions can, and must, be consistent with a vibrant and growing economy and supply of reliable, affordable electricity to support that economy. It further reflects the growing trend, as exemplified by many state and local clean energy policies and programs, to shift energy production away from carbon-intensive fuels to a modern, more sustainable system that puts greater reliance on renewable energy, energy efficiency and other low-carbon energy options.

c. State Plans

i. Plan Approach

Each state will determine, and include in its plan, emission performance levels for its affected EGUs that are equivalent to the state-specific CO_2 goal in the emission guidelines, as well as the measures needed to achieve those levels and the overall goal. As part of determining these levels, the state will decide whether it will adopt the rate-based form of the goal established by the EPA or translate the rate-based goal to a mass-based goal. The state must then establish a standard, or set of standards, of performance, as well as implementing and enforcing measures, to achieve the emission performance level specified in the state plan. The state may choose the measures it will include in its plan to achieve its goal. The state may use the same set of measures as in the EPA's approach to setting the goals, or the state may use other or additional measures to achieve the required CO_2 reductions.

A state plan must include enforceable CO_2 emission limits that apply to affected EGUs. In doing so, a state plan may take a portfolio approach, which could include enforceable CO_2 emission limits that apply to affected EGUs as well as other enforceable measures, such as RE and demand-side EE measures, that avoid EGU CO_2 emissions and are implemented by the state or by another entity. The plan must also include a process for reporting on plan implementation, progress toward achieving CO_2 goals, and implementation of corrective actions, if necessary. No less frequently than every two rolling calendar years, beginning January 1, 2022, the state will be required to compare emission performance achieved by affected EGUs

in the state with the emissions performance projected in the state plan, and report that to the EPA.

In this action, the EPA is also proposing guidelines for states to follow in developing their plans. These guidelines include approvability criteria, requirements for state plan components, the process and timing for state plan submittal and the process and timing for demonstrating achievement of the CO_2 emission performance level in the state plan. The proposed guidelines provide states with options for meeting the state-specific goals established by the EPA in a flexible manner that accommodates a diverse range of state approaches. The plan guidelines provide the states with the ability to achieve the full reductions over a multi-year period, through a variety of reduction strategies, using state-specific or multi-state approaches that can be achieved on either a rate or mass basis. They also address several key policy considerations that states can be expected to contemplate in developing their plans.

With respect to the structure of the state plans, the EPA, in its extensive outreach efforts, heard from a wide range of stakeholders that the EPA should authorize state plans to include a portfolio of actions that encompass a diverse set of programs and measures that achieve either a rate-based or mass-based emission performance level for affected EGUs but that do not place legal responsibility for achieving the entire amount of the emission performance level on the affected EGUs. In view of this strong sentiment from stakeholders, the EPA is proposing that state plans that take this portfolio approach would be approvable, provided that they meet other key requirements such as achieving the required emission reductions over the appropriate timeframes. Plans that do directly assure that affected EGUs achieve all of the required emission reductions (such as the mass-based programs being implemented in California and the RGGI states) would also be approvable provided that they meet other key requirements, such as achieving the required emission reductions over the appropriate timeframes.

ii. State Plan Components

The EPA is proposing to evaluate and approve state plans based on four general criteria: (1) Enforceable measures that reduce EGU CO_2 emissions; (2) projected achievement of emission performance equivalent to the goals established by the EPA, on a timeline equivalent to that in the emission guidelines; (3) quantifiable and verifiable emission reductions; and (4) a process for reporting on plan implementation, progress toward achieving CO_2 goals, and implementation of corrective actions, if necessary. In addition, each state plan must follow the EPA framework regulations at 40 CFR 60.23. The proposed components of states plans are:

- Identification of affected entities
- Description of plan approach and geographic scope
- Identification of state emission performance level
- Demonstration that plan is projected to achieve emission performance level
- Identification of emission standards
- Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable
- Identification of monitoring, reporting, and recordkeeping requirements
- Description of state reporting
- Identification of milestones
- Identification of backstop measures
- Certification of hearing on state plan
- Supporting material

iii. Process for State Plan Submittal and Review

Recognizing the urgent need for actions to reduce GHG emissions, and in accordance with the Presidential Memorandum,[10] the EPA expects to finalize this rulemaking by June 1, 2015. The Presidential Memorandum also calls for a deadline of June 30, 2016, for states to submit their state plans. The EPA is proposing that each state must submit a plan to the EPA by June 30, 2016. However, the EPA recognizes that some states may need more than one year to complete all of the actions needed for their final state plans, including technical work, state legislative and rulemaking activities, coordination with third parties, and coordination among states involved in multi-state plans. Therefore, the EPA is proposing an optional two-phased submittal process for state plans. Each state would be required to submit a plan by June 30, 2016, that contains certain required components. If a state needs additional time to submit a complete plan, then the state must submit an initial plan by June 30, 2016 that documents the reasons the state needs more time and includes commitments to concrete steps that will ensure that the state will submit a complete plan by June 30, 2017 or 2018, as appropriate. To be approvable, the initial plan must include specific components, including a description of the plan approach, initial quantification of the level of emission performance that will be achieved in the plan, a commitment to maintain existing measures that limit CO_2 emissions, an explanation of the path to completion, and a summary of the state's response to any significant public comment on the approvability of the initial plan, as described in Section VIII.E of this preamble.

If the initial plan includes those components and if the EPA does not notify the state that the initial plan does not contain the required components, the extension of time to submit a complete plan will be deemed granted and a state would have until June 30, 2017, to submit a complete plan if the geographic scope of the plan is limited to that state. If the state develops a plan that includes a multi-state approach, it would have until June 30, 2018 to submit a complete plan. Further, the EPA is proposing that states participating in a multi-state plan may submit a single joint plan on behalf of all of the participating states.

Following submission of final plans, the EPA will review plan submittals for approvability. Given the diverse approaches states may take to meet the emission performance goals in the emission guidelines, the EPA is proposing to extend the period for EPA review and approval or disapproval of plans from the four-month period provided in the EPA framework regulations to a twelve-month period.

iv. Timing of Compliance

As states, industry groups and other stakeholders have made clear, the EPA recognizes that the measures states have been and will be taking to reduce CO_2 emissions from existing EGUs can take time to implement. Thus, we are proposing that, while states must begin to make reductions by 2020, full compliance with the CO_2 emission performance level in the state plan must be achieved by no later than 2030. Under this proposed option, a state would need to meet an interim CO_2 emission performance level on average over the 10-year period from 2020–2029, as well as achieve its final CO_2 emission performance level by 2030 and maintain that level subsequently. This proposed option is based on the application of a range of measures from all four building blocks, and the agency believes that this approach for compliance timing is reasonable and appropriate and would best support the optimization of overall

[10] Presidential Memorandum—Power Sector Carbon Pollution Standards, June 25, 2013. *http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.*

CO_2 reductions. The agency is also requesting comment on an alternative option, a 5-year period for compliance, in combination with a less stringent set of CO_2 emission performance levels. These options are fully described in Section VIII of this preamble, and the state goals associated with the alternative option are described in Section VII.E of this preamble. The EPA is also seeking comment on different combinations of building blocks and different levels of stringency for each building block.

The EPA is also proposing that measures that a state takes after the date of this proposal, or programs already in place, which result in CO_2 emission reductions during the 2020–2030 period, would apply toward achievement of the state's 2030 CO_2 emission goal. Thus, states with currently existing programs and policies, and states that put in place new programs and policies early, will be better positioned to achieve the goals.

v. Resources for States

To respond to requests from states for methodologies, tools and information to assist them in designing and implementing their plans, the EPA, in consultation with the U.S. Department of Energy and other federal agencies, as well as states, is collecting and developing available resources and is making those resources available to the states via a dedicated Web site.[11] As we and others continue to develop tools, templates and other resources, we will update the Web site. We intend, during the public comment period, to work actively with the states on resources that will be helpful to them in both developing and implementing their plans.

3. Projected National-Level Emission Reductions

Under the proposed guidelines, the EPA projects annual CO_2 reductions of 26 to 30 percent below 2005 levels depending upon the compliance year. These guidelines will also result in important reductions in emissions of criteria air pollutants, including sulfur dioxide (SO_2), nitrogen oxides (NO_X) and directly emitted fine particulate matter ($PM_{2.5}$). A thorough discussion of the EPA's analysis is presented in Section X.A of this preamble and in Chapter 3 of the Regulatory Impact Analysis (RIA) included in the docket for this rulemaking.

4. Costs and Benefits

Actions taken to comply with the proposed guidelines will reduce emissions of CO_2 and other air pollutants, including SO_2, NO_X and directly emitted $PM_{2.5}$, from the electric power industry. States will make the ultimate determination as to how the emission guidelines are implemented. Thus, all costs and benefits reported for this action are illustrative estimates. The EPA has calculated illustrative costs and benefits in two ways: One based on an assumption of individual state plans and another based on an assumption that states will opt for multi-state plans. The illustrative costs and benefits are based upon compliance approaches that reflect a range of measures consisting of improved operations at EGUs, dispatching lower-emitting EGUs and zero-emitting energy sources, and increasing levels of end-use energy efficiency.

Assuming that states comply with the guidelines collaboratively (referred to as the regional compliance approach), the EPA estimates that, in 2020, this proposal will yield monetized climate benefits of approximately $17 billion (2011$) using a 3 percent discount rate (model average) relative to the 2020 base case, as shown in Table 1.[12] The air pollution health co-benefits associated with reducing exposure to ambient $PM_{2.5}$ and ozone through emission reductions of precursor pollutants in 2020 are estimated to be $16 billion to $37 billion using a 3 percent discount rate and $15 billion to $34 billion (2011$) using a 7 percent discount rate relative to the 2020 base case. The annual compliance costs are estimated using the Integrated Planning Model (IPM) and include demand-side energy efficiency program and participant costs as well as monitoring, reporting and recordkeeping costs. In 2020, total compliance costs of this proposal are approximately $5.5 billion (2011$). The quantified net benefits (the difference between monetized benefits and compliance costs) in 2020 are estimated to be $28 billion to $49 billion (2011$) using a 3 percent discount rate (model average). As reflected in Table 2, climate benefits are approximately $30 billion in 2030 using a 3 percent discount rate (model average, 2011$) relative to the 2030 base case assuming a regional compliance approach for the proposal. Health co-benefits are estimated to be approximately $25 to $59 billion (3 percent discount rate) and $23 to $54 billion (7 percent discount rate) relative to the 2030 base case (2011$). In 2030, total compliance costs for the proposed option regional approach are approximately $7.3 billion (2011$). The net benefits for this proposal increase to approximately $48 billion to $82 billion (3 percent discount rate model average, 2011$) in 2030 for the proposed option regional compliance approach.

In comparison, if states choose to comply with the guidelines on a state-specific basis (referred to as state compliance approach), the climate benefits in 2020 are expected to be approximately $18 billion (3 percent discount rate, model average, 2011$), as Table 1 shows. Health co-benefits are estimated to be $17 to $40 billion (3 percent discount rate) and $15 to $36 billion (7 percent discount rate). Total compliance costs are approximately $7.5 billion annually in 2020. Net benefits in 2020 are estimated to be $27 to $50 billion (3 percent model average discount rate, 2011$). In 2030, as shown on Table 2, climate benefits are approximately $31 billion using a 3 percent discount rate (model average, 2011$) relative to the 2030 base case assuming a state compliance approach. Health co-benefits are estimated to be approximately $27 to $62 billion (3 percent discount rate) and $24 to $56 billion (7 percent discount rate) relative to the 2030 base case (2011$). In 2030, total compliance costs for the state approach are approximately $8.8 billion (2011$). In 2030, these net benefits are estimated to be approximately $49 to $84 billion (3 percent discount rate, 2011$) assuming a state compliance approach.

[11] *www2.epa.gov/cleanpowerplantoolbox.*

[12] The EPA has used social cost of carbon (SCC) estimates—i.e., the monetary value of impacts associated with a marginal change in CO_2 emissions in a given year—to analyze CO_2 climate impacts of this rulemaking. The four SCC estimates are associated with different discount rates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), and each increases over time. In this summary, the EPA provides the estimate of climate benefits associated with the SCC value deemed to be central: The model average at 3 percent discount rate.

TABLE 1—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE PROPOSED GUIDELINES IN 2020 [a]

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Proposed Guidelines Regional Compliance Approach		
Climate benefits [b]	$17.	
Air pollution health co-benefits [c]	$16 to $37	$15 to $34.
Total Compliance Costs [d]	$5.5	$5.5.
Net Monetized Benefits [e]	$28 to $49	$26 to $45.
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.3 tons of Hg. Ecosystem Effects. Visibility impairment.	
Proposed Guidelines State Compliance Approach		
Climate benefits [b]	$18	
Air pollution health co-benefits [c]	$17 to $40	$15 to $36.
Total Compliance Costs [d]	$7.5	$7.5.
Net Monetized Benefits [e]	$27 to $50	$26 to $46.
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.5 tons. Ecosystem effects. Visibility impairment.	

[a] All estimates are for 2020, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. As shown in the RIA, climate benefits are also estimated using the other three SCC estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed guidelines and a discount rate of approximately 5%. This estimate includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

TABLE 2—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE PROPOSED GUIDELINES IN 2030 [a]

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Proposed Guidelines Regional Compliance Approach		
Climate benefits [b]	$30.	
Air pollution health co-benefits [c]	$25 to $59	$23 to $54.
Total Compliance Costs [d]	$7.3	$7.3.
Net Monetized Benefits [e]	$48 to $82	$46 to $77.
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.7 tons of Hg and 580 tons of HCl. Ecosystem Effects. Visibility impairment.	
Proposed Guidelines State Compliance Approach		
Climate benefits [b]	$31.	
Air pollution health co-benefits [c]	$27 to $62	$24 to $56.
Total Compliance Costs [d]	$8.8	$8.8.
Net Monetized Benefits [e]	$49 to $84	$46 to $79.

TABLE 2—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR THE PROPOSED GUIDELINES IN 2030 [a]—Continued

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 2.1 tons of Hg and 590 tons of HCl. Ecosystem effects. Visibility impairment.	

[a] All estimates are for 2030, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. As shown in the RIA, climate benefits are also estimated using the other three SCC estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed guidelines and a discount rate of approximately 5%. This estimate includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

There are additional important benefits that the EPA could not monetize. These unquantified benefits include climate benefits from reducing emissions of non-CO_2 greenhouse gases (e.g., nitrous oxide and methane) [13] and co-benefits from reducing direct exposure to SO_2, NO_X and hazardous air pollutants (e.g., mercury and hydrogen chloride), as well as from reducing ecosystem effects and visibility impairment.

In addition to the cost and benefits of the rule, the EPA projects the employment impacts of the guidelines. We project job gains and losses relative to base case for the electric generation, coal and natural gas production, and demand side energy efficiency sectors. In 2020, we project job growth of 25,900 to 28,000 job-years [14] in the power production and fuel extraction sectors, and we project an increase of 78,800 jobs in the demand-side energy efficiency sector.

Based upon the foregoing, it is clear that the monetized benefits of this proposal are substantial and far outweigh the costs.

B. Organization and Approach for This Proposed Rule

This action presents the EPA's proposed emission guidelines for states to consider in developing plans to reduce GHG emissions from the electric power sector. Section II provides background on climate change impacts from GHG emissions, GHG emissions from fossil fuel-fired EGUs and the utility power sector and CAA section 111(d) requirements. Section III presents a summary of the EPA's stakeholder outreach efforts, key messages provided by stakeholders, state policies and programs that reduce GHG emissions, and conclusions. In Section IV of the preamble, we present a summary of the rule requirements and the legal basis for these. Section V explains the EPA authority to regulate CO_2 and EGUs, identifies affected sources, and describes the proposed treatment of source categories. Section VI describes the use of building blocks for setting state goals and key considerations in doing so. Sections VII and VIII provide explanations of the proposed state-specific goals and the proposed requirements for state plans, respectively. Implications for the new source review and Title V programs and potential interactions with other EPA rules are described in Section IX. Impacts of the proposed action are then described in Section X, followed by a discussion of statutory and executive order reviews in Section XI and the statutory authority for this action in Section XII.

We note that this rulemaking overlaps in certain respects with two other related rulemakings: The January 2014 proposed rulemaking that the EPA published on January 8, 2014 for CO_2 emissions from newly constructed affected sources,[15] and the rulemaking for modified and reconstructed sources that the EPA is proposing at the same time as this rulemaking. Each of these three rulemakings is independent of the other two, and each has its own rulemaking docket. Accordingly, commenters who wish to comment on any aspect of this rulemaking, including a topic that overlaps an aspect of one or both of the other two related rulemakings, should make those comments on this rulemaking.

II. Background

In this section, we discuss climate change impacts from GHG emissions, both on public health and public welfare, present information about GHG emissions from fossil fuel fired EGUs, and summarize the statutory and regulatory requirements relevant to this rulemaking.

A. Climate Change Impacts From GHG Emissions

In 2009, the EPA Administrator issued the document known as the Endangerment Finding under CAA section 202(a)(1).[16] In the Endangerment Finding, which focused on public health and public welfare impacts within the United States, the Administrator found that elevated concentrations of GHGs in the atmosphere may reasonably be anticipated to endanger public health and welfare of current and future generations. We summarize these adverse effects on public health and welfare briefly here.

1. Public Health Impacts Detailed in the 2009 Endangerment Finding

Climate change caused by human emissions of GHGs threatens public health in multiple ways. By raising average temperatures, climate change

[13] Although CO_2 is the predominant greenhouse gas released by the power sector, electricity generating units also emit small amounts of nitrous oxide and methane. See RIA Chapter 2 for more detail about power sector emissions and the U.S. Greenhouse Gas Reporting Program's power sector summary, *http://www.epa.gov/ghgreporting/ghgdata/reported/powerplants.html.*

[14] A job-year is not an individual job; rather, a job-year is the amount of work performed by the equivalent of one full-time individual for one year. For example, 20 job-years in 2020 may represent 20 full-time jobs or 40 half-time jobs.

[15] 79 FR 1430.

[16] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,'' 74 FR 66,496 (Dec. 15, 2009) (''Endangerment Finding'').

increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the United States. Compared to a future without climate change, climate change is expected to increase ozone pollution over broad areas of the U.S., including in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality. Other public health threats also stem from projected increases in intensity or frequency of extreme weather associated with climate change, such as increased hurricane intensity, increased frequency of intense storms, and heavy precipitation. Increased coastal storms and storm surges due to rising sea levels are expected to cause increased drownings and other health impacts. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

2. Public Welfare Impacts Detailed in the 2009 Endangerment Finding

Climate change caused by human emissions of GHGs also threatens public welfare in multiple ways. Climate changes are expected to place large areas of the country at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas are expected to face increased risks from storm and flooding damage to property, as well as adverse impacts from rising sea level, such as land loss due to inundation, erosion, wetland submergence and habitat loss. Climate change is expected to result in an increase in peak electricity demand, and extreme weather from climate change threatens energy, transportation, and water resource infrastructure. Climate change may exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities. Climate change also is very likely to fundamentally rearrange U.S. ecosystems over the 21st century. Though some benefits may balance adverse effects on agriculture and forestry in the next few decades, the body of evidence points towards increasing risks of net adverse impacts on U.S. food production, agriculture and forest productivity as temperature continues to rise. These impacts are global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S.

3. New Scientific Assessments

As outlined in Section VIII.A. of the 2009 Endangerment Finding, the EPA's approach to providing the technical and scientific information to inform the Administrator's judgment regarding the question of whether GHGs endanger public health and welfare was to rely primarily upon the recent, major assessments by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) of the National Academies. These assessments addressed the scientific issues that the EPA was required to examine, were comprehensive in their coverage of the GHG and climate change issues, and underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of U.S. government review. Since the administrative record concerning the Endangerment Finding closed following the EPA's 2010 Reconsideration Denial, a number of such assessments have been released. These assessments include the IPCC's 2012 ''Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation'' (SREX) and the 2013–2014 Fifth Assessment Report (AR5), the USGCRP's 2014 ''Climate Change Impacts in the United States'' (Climate Change Impacts), and the NRC's 2010 ''Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean'' (Ocean Acidification), 2011 ''Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia'' (Climate Stabilization Targets), 2011 ''National Security Implications for U.S. Naval Forces'' (National Security Implications), 2011 ''Understanding Earth's Deep Past: Lessons for Our Climate Future'' (Understanding Earth's Deep Past), 2012 ''Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future'', 2012 ''Climate and Social Stress: Implications for Security Analysis'' (Climate and Social Stress), and 2013 ''Abrupt Impacts of Climate Change'' (Abrupt Impacts) assessments.

The EPA has reviewed these new assessments and finds that the improved understanding of the climate system they present strengthens the case that GHGs endanger public health and welfare.

In addition, these assessments highlight the urgency of the situation as the concentration of CO_2 in the atmosphere continues to rise. Absent a reduction in emissions, a recent National Research Council of the National Academies assessment projected that concentrations by the end of the century would increase to levels that the Earth has not experienced for millions of years.[17] In fact, that assessment stated that ''the magnitude and rate of the present greenhouse gas increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in Earth history.'' [18]

What this means, as stated in another NRC assessment, is that:

> Emissions of carbon dioxide from the burning of fossil fuels have ushered in a new epoch where human activities will largely determine the evolution of Earth's climate. Because carbon dioxide in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe. Therefore, emission reductions choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia.[19]

Moreover, due to the time-lags inherent in the Earth's climate, the Climate Stabilization Targets assessment notes that the full warming from any given concentration of CO_2 reached will not be realized for several centuries.

The recently released USGCRP ''Climate Change Impacts'' assessment [20] emphasizes that climate change is already happening now and it is happening in the United States. The assessment documents the increases in some extreme weather and climate events in recent decades, the damage and disruption to infrastructure and agriculture, and projects continued increases in impacts across a wide range of peoples, sectors, and ecosystems.

These assessments underscore the urgency of reducing emissions now: Today's emissions will otherwise lead to raised atmospheric concentrations for thousands of years, and raised Earth system temperatures for even longer. Emission reductions today will benefit the public health and public welfare of current and future generations.

Finally, it should be noted that the concentration of carbon dioxide in the atmosphere continues to rise dramatically. In 2009, the year of the Endangerment Finding, the average concentration of carbon dioxide as

[17] National Research Council, Understanding Earth's Deep Past, p. 1.

[18] Id., p.138.

[19] National Research Council, Climate Stabilization Targets, p. 3.

[20] U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment, May 2014 Available at *http://nca2014.globalchange.gov/*.

measured on top of Mauna Loa was 387 parts per million.[21] The average concentration in 2013 was 396 parts per million. And the monthly concentration in April of 2014 was 401 parts per million, the first time a monthly average has exceeded 400 parts per million since record keeping began at Mauna Loa in 1958, and for at least the past 800,000 years according to ice core records.[22]

B. GHG Emissions From Fossil Fuel-Fired EGUs

Fossil fuel-fired electric utility generating units (EGUs) are by far the largest emitters of GHGs, primarily in the form of CO_2, among stationary sources in the U.S., and among fossil fuel-fired units, coal-fired units are by far the largest emitters. This section describes the amounts of those emissions and places those amounts in the context of the national inventory of GHGs.

The EPA prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks [23] (the U.S. GHG Inventory) to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sectors. It provides the information in Table 3 below, which presents total U.S. anthropogenic emissions and sinks [24] of GHGs, including CO_2 emissions, for the years 1990, 2005 and 2012.

TABLE 3—U.S. GHG EMISSIONS AND SINKS BY SECTOR

[Teragram carbon dioxide equivalent (Tg CO_2 Eq.)] [25]

Sector	1990	2005	2012
Energy	5,260.1	6,243.5	5,498.9
Industrial Processes	316.1	334.9	334.4
Solvent and Other Product Use	4.4	4.4	4.4
Agriculture	473.9	512.2	526.3
Land Use, Land-Use Change and Forestry	13.7	25.5	37.8
Waste	165.0	133.2	124.0
Total Emissions	6,233.2	7,253.8	6,525.6
Land Use, Land-Use Change and Forestry (Sinks)	(831.3)	(1,030.7)	(979.3)
Net Emissions (Sources and Sinks)	5,402.1	6,223.1	5,546.3

Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.7 percent of total 2012 GHG emissions.[26] In 2012, fossil fuel combustion by the electric power sector—entities that burn fossil fuel and whose primary business is the generation of electricity—accounted for 38.7 percent of all energy-related CO_2 emissions.[27] Table 4 below presents total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2005 and 2012.

TABLE 4—U.S. GHG EMISSIONS FROM GENERATION OF ELECTRICITY FROM COMBUSTION OF FOSSIL FUELS

[Tg CO_2] [28]

GHG emissions	1990	2005	2012
Total CO_2 from fossil fuel combustion EGUs	1,820.8	2,402.1	2,022.7
—from coal	1,547.6	1,983.8	1,511.2
—from natural gas	175.3	318.8	492.2
—from petroleum	97.5	99.2	18.8

C. The Utility Power Sector

Electricity in the United States is generated by a range of sources—from power plants that use fossil fuels like coal, oil, and natural gas, to non-fossil sources, such as nuclear, solar, wind and hydroelectric power. In 2013, over 67 percent of power in the U.S. was generated from the combustion of coal, natural gas, and other fossil fuels, over 40 percent from coal and over 26 percent from natural gas.[29] In recent years, though, the proportion of new renewable generation coming on line has increased dramatically. For instance, over 38 percent of new generating capacity (over 5 GW out of 13.5 GW) built in 2013 used renewable power generation technologies.[30]

[21] *ftp://aftp.cmdl.noaa.gov/products/trends/co2/co2_annmean_mlo.txt.*

[22] *http://www.esrl.noaa.gov/gmd/ccgg/trends/.*

[23] ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[24] Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep sea reservoirs of carbon dioxide.

[25] From Table ES–4 of ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012, Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[26] From Table ES–2 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[27] From Table 3–1 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[28] From Table 3–5 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[29] U.S. Energy Information Administration (EIA), ''Table 7.2b Electricity Net Generation: Electric Power Sector Electric Power Sector,'' data from April 2014 Monthly Energy Review, release date April 25, 2014. Available at: *http://www.eia.gov/totalenergy/data/browser/xls.cfm?tbl=T07.02B&freq=m.*

[30] Based on Table 6.3 (New Utility Scale Generating Units by Operating Company, Plant, Month, and Year) of the U.S. Energy Information Administration (EIA) Electric Power Monthly, data for December 2013, for the following renewable

Continued

This range of different power plants generates electricity that is transmitted and distributed through a complex system of interconnected components to industrial, business, and residential consumers.

The utility power sector is unique in that, unlike other sectors where the sources operate independently and on a local scale, power sources operate in a complex, interconnected grid system that typically is regional in scale. In addition, the U.S. economy depends on this sector for a reliable supply of power at a reasonable cost.

In the U.S., much of the existing power generation fleet in the infrastructure is aging. There has been, and continues to be, technological advancement in many areas, including energy efficiency, solar power generation, and wind power generation. Advancements and innovation in power sector technologies provide the opportunity to address CO_2 emission levels at affected power plants while at the same time improving the overall power system in the U.S. by lowering the carbon intensity of power generation, and ensuring a continued reliable supply of power at a reasonable cost.

D. Statutory and Regulatory Requirements

Clean Air Act section 111, which Congress enacted as part of the 1970 Clean Air Act Amendments, establishes mechanisms for controlling emissions of air pollutants from stationary sources. This provision requires the EPA to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' [31] The EPA has listed more than 60 stationary source categories under this provision.[32] Once the EPA lists a source category, the EPA must, under CAA section 111(b)(1)(B), establish ''standards of performance'' for emissions of air pollutants from new sources in the source categories.[33] These standards are known as new source performance standards (NSPS), and they are national requirements that apply directly to the sources subject to them.

When the EPA establishes NSPS for new sources in a particular source category, the EPA is also required, under CAA section 111(d)(1), to prescribe regulations for states to submit plans regulating existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the NAAQS or regulated under the CAA section 112 requirements for hazardous air pollutants (HAP). CAA section 111(d)'s mechanism for regulating existing sources differs from the one that CAA section 111(b) provides for new sources because CAA section 111(d) contemplates states submitting plans that establish ''standards of performance'' for the affected sources and that contain other measures to implement and enforce those standards.

''Standards of performance'' are defined under CAA section 111(a)(1) as standards for emissions that reflect the emission limitation achievable from the ''best system of emission reduction,'' considering costs and other factors, that ''the Administrator determines has been adequately demonstrated.'' CAA section 111(d)(1) grants states the authority, in applying a standard of performance to particular sources, to take into account the source's remaining useful life or other factors.

Under CAA section 111(d), a state must submit its plan to the EPA for approval, and the EPA must approve the state plan if it is ''satisfactory.'' [34] If a state does not submit a plan, or if the EPA does not approve a state's plan, then the EPA must establish a plan for that state.[35] Once a state receives the EPA's approval for its plan, the provisions in the plan become federally enforceable against the entity responsible for noncompliance, in the same manner as the provisions of an approved SIP under CAA section 110. Although affected EGUs located in Indian country operate as part of the interconnected system of electricity production and distribution, those EGUs would not be encompassed within a state's CAA section 111(d) plan. Instead, a tribe that has one or more affected EGUs located in its area of Indian country [36] would have the opportunity, but not the obligation, to establish a plan that establishes standards of performance for CO_2 emissions from affected EGUs for its tribal lands.

The EPA issued regulations implementing CAA section 111(d) in 1975,[37] and has revised them in the years since.[38] (We refer to the regulations generally as the implementing regulations, and we refer to the 1975 rulemaking as the framework regulations.) These regulations provide that, in promulgating requirements for sources under CAA section 111(d), the EPA first develops regulations known as ''emission guidelines,'' which establish binding requirements that states must address when they develop their plans.[39] The implementing regulations also establish timetables for state and EPA action: States must submit state plans within 9 months of the EPA's issuance of the guidelines,[40] and the EPA must take final action on the state plans within 4 months of the due date for those plans,[41] although the EPA has authority to extend those deadlines.[42] In the present rulemaking, the EPA is following the requirements of the implementing regulations, and is not re-opening them, except that the EPA is extending the timetables, as described below.

Over the last forty years, under CAA section 111(d), the agency has regulated four pollutants from five source categories (i.e., sulfuric acid plants (acid mist), phosphate fertilizer plants (fluorides), primary aluminum plants (fluorides), Kraft pulp plants (total reduced sulfur), and municipal solid waste landfills (landfill gases)).[43] In addition, the agency has regulated additional pollutants under CAA section 111(d) in conjunction with CAA

energy sources: solar, wind, hydro, geothermal, landfill gas, and biomass. Available at: *http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_03*.

[31] CAA § 111(b)(1)(A).

[32] See 40 CFR 60 subparts Cb–OOOO.

[33] CAA § 111(b)(1)(B), 111(a)(1).

[34] CAA section 111(d)(2)(A).

[35] CAA section 111(d)(2)(A).

[36] The EPA is aware of at least four affected sources located in Indian Country: Two on Navajo lands—the Navajo Generating Station and the Four Corners Generating Station; one on Ute lands—the Bonanza Generating Station; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.

[37] ''State Plans for the Control of Certain Pollutants From Existing Facilities,'' 40 FR 53,340 (Nov. 17, 1975).

[38] The most recent amendment was in 77 FR 9304 (Feb. 16, 2012).

[39] 40 CFR 60.22. In the 1975 rulemaking, the EPA explained that it used the term ''emissions guidelines''—instead of emissions limitations—to make clear that guidelines would not be binding requirements applicable to the sources, but instead are ''criteria for judging the adequacy of State plans.'' 40 FR at 53,343.

[40] 40 CFR 60.23(a)(1).

[41] 40 CFR 60.27(b).

[42] *See 40 CFR 60.27(a).*

[43] *See* ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 Fed. Reg. 12,022 (Mar. 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55,796 (Oct. 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29,828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26,294 (Apr. 17, 1980); ''Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule,'' 61 FR 9905 (Mar. 12, 1996).

section 129.[44] The agency has not previously regulated CO_2 or any other greenhouse gas under CAA section 111(d).

The EPA's previous CAA section 111(d) actions were necessarily geared toward the pollutants and industries regulated. Similarly, in this proposed rulemaking, in defining CAA section 111(d) emission guidelines for the states and determining the BSER, the EPA believes that taking into account the particular characteristics of carbon pollution, the interconnected nature of the power sector and the manner in which EGUs are currently operated is warranted. Specifically, the operators themselves treat increments of generation as interchangeable between and among sources in a way that creates options for relying on varying utilization levels, lowering carbon generation, and reducing demand as components of the overall method for reducing CO_2 emissions. Doing so results in a broader, forward-thinking approach to the design of programs to yield critical CO_2 reductions that improve the overall power system by lowering the carbon intensity of power generation, while offering continued reliability and cost-effectiveness. These opportunities exist in the power sector in ways that were not relevant or available for other industries for which the EPA has established CAA section 111(d) emission guidelines.[45]

In this action, the EPA is proposing emission guidelines for states to follow in developing their plans to reduce emissions of CO_2 from the electric power sector.

III. Stakeholder Outreach and Conclusions

A. Stakeholder Outreach

1. The President's Call for Engagement

Following the direction of the Presidential Memorandum to the Administrator (June 25, 2013),[46] this proposed rule was developed after extensive and vigorous outreach to stakeholders and the general public. The Presidential Memorandum instructed the Administrator to inaugurate the process for developing standards through direct engagement with the states and a full range of stakeholders:

> Launch this effort through direct engagement with States, as they will play a central role in establishing and implementing standards for existing power plants, and, at the same time, with leaders in the power sector, labor leaders, non-governmental organizations, other experts, tribal officials, other stakeholders, and members of the public, on issues informing the design of the program.

2. Educating the Public and Stakeholder Outreach

To carry out this stakeholder outreach, the EPA embarked on an unprecedented pre-proposal outreach effort. From consumer groups to states to power plant owner/operators to technology innovators, the EPA sought input from all perspectives.

The EPA began the outreach efforts with a webinar and associated teleconferences to establish a common understanding of the basic requirements and process of CAA section 111(d). The August 27, 2013 overview presentation was offered as a webinar for state and tribal officials, ''Building a Common Understanding: Clean Air Act and Upcoming Carbon Pollution Guidelines for Existing Power Plants.''

The EPA followed up on the presentation by offering four national teleconference calls with representatives from states, tribes, industry, environmental justice organizations, community organizations and environmental representatives. The teleconferences offered a venue for stakeholders to ask questions of the EPA about the overview presentation and for the EPA to gather initial reactions from stakeholders. Stakeholders and members of the public continued to view and refer to the overview presentation throughout the outreach process. By May 2014, the presentation had been viewed more than 5,600 times.

The agency also provided mechanisms for anyone from the public to provide input during the pre-proposal development of this action. The EPA set up two user-friendly options to accept input during the pre-proposal period—email and a web-based form. The EPA has received more than 2,000 emails offering input into the development of these guidelines.

These emails and other materials provided to the EPA are posted on line as part of a non-regulatory docket, EPA Docket ID No. EPA–HQ–OAR–2014–0020, at *www.regulations.gov*. All of the documents on which this proposal is based are available at Docket ID No. EPA–HQ–OAR–2013–0602, at *www.regulations.gov*. However, while the information collected through extensive outreach helped the agency formulate this proposal, we are not relying on all of the documents, emails, and other information included in the informational docket that was established as a part of that outreach effort, nor will the EPA be responding to specific comments or issues raised during the outreach effort. Rather, we have included in the docket for this proposal all of the information we relied on for this action.

The agency has encouraged, organized, and participated in hundreds of meetings about CAA section 111(d) and reducing carbon pollution from existing power plants. Attendees at these various meetings have included states and tribes, members of the public, and representatives from multiple industries, labor leaders, environmental groups and other non-governmental organizations. The direct engagement has brought together a variety of states and stakeholders to discuss a wide range of issues related to the electricity sector and the development of emission guidelines under CAA section 111(d). The meetings occurred in Washington, DC, and at locations across the country. The meetings were attended by the EPA Regional Administrators, managers and staff and who are playing or will play key roles in developing and implementing the rule.

Part of this effort included the agency's holding of 11 public listening sessions; one national listening session in Washington, DC and 10 listening sessions in locations in the EPA regional offices across the country. All of the outreach meetings were designed to solicit policy ideas, concerns and technical information from stakeholders about using CAA section 111(d).

This outreach process has produced a wealth of information which has informed this proposal significantly. The pre-proposal outreach efforts far exceeded what is required of the agency in the normal course of a rulemaking process, and the EPA expects that the dialog with states and stakeholders will continue throughout the process and even after the rule is finalized. The EPA recognizes the importance of working with all stakeholders, and in particular with the states, to ensure a clear and common understanding of the role the

[44] *See, e.g.,* ''Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Final Rule,'' 76 FR 15,372 (Mar. 21, 2011).

[45] *See* ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12,022 (Mar. 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55,796 (Oct. 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29,828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26,294 (Apr. 17, 1980); ''Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule,'' 61 F R 9905 (Mar. 12, 1996).

[46] Presidential Memorandum—Power Sector Carbon Pollution Standards, June 25, 2013. *http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.*

states will play in addressing carbon pollution from power plants.

3. Public Listening Sessions

More than 3,300 people attended the public listening sessions held in 11 cities across the country. Holding the listening sessions at the EPA's regional offices offered thousands of people from different parts of the country the opportunity to provide input to EPA officials in accessible venues. In addition to being well located, holding the sessions in regional offices also allowed the agency to use resources prudently and enabled a variety of the EPA staff involved in the development and ultimate implementation of this upcoming rule to attend and learn from the views expressed.

More than 1,600 people spoke at the 11 listening sessions. Speakers included Members of Congress, other public officials, industry representatives, faith-based organizations, unions, environmental groups, community groups, students, public health groups, energy groups, academia and concerned citizens. Participants shared a range of perspectives. Many were concerned by the impacts of climate change on their health and on future generations, others worried about the impact of regulations on the economy. Their support for the agency's efforts varied.

Summaries of these 11 public listening sessions are available at *www.regulations.gov* at EPA Docket ID No. EPA–HQ–OAR–2014–0020.

4. State Officials

Since fall 2013, the agency provided multiple opportunities for the states to inform this proposal. In addition, the EPA organized, encouraged and attended meetings to discuss multi-state planning efforts. Because of the interconnectedness of the power sector, and the fact that electricity generated at power plants crosses state lines, states, utilities and ratepayers may benefit from states working together to address the requirements of this rulemaking implementation. The meetings provided state leaders, including governors, environmental commissioners, energy officers, public utility commissioners, and air directors, opportunities to engage with the EPA officials.

Agency officials listened to ideas, concerns and details from states, including from states with a wide range of experience in reducing carbon pollution from power plants. The agency has collected policy papers from states with overarching energy goals and technical details on the states' electricity sector. The agency has engaged, and will continue to engage with, all of the 50 states throughout the rulemaking process.

5. Tribal Officials

The EPA conducted significant outreach to tribes, who are not required to—but may—develop or adopt Clean Air Act programs. The EPA is aware of three coal-fired power plants and one natural gas-fired EGU located in Indian country but is not aware of any EGUs that are owned or operated by tribal entities.

The EPA conducted outreach to tribal environmental staff and offered consultation with tribal officials in developing this action. Because the EPA is aware of tribal interest in this proposed rule, the EPA offered consultation with tribal officials early in the process of developing the proposed regulation to permit tribes to have meaningful and timely input into its development.

The EPA sent consultation letters to 584 tribal leaders. The letters provided information regarding the EPA's development of emission guidelines for existing power plants and offered consultation. None have requested consultation. Tribes were invited to participate in the national informational webinar held August 27, 2013. In addition, a consultation/outreach meeting was held on September 9, 2013, with tribal representatives from some of the 584 tribes. The EPA representatives also met with tribal environmental staff with the National Tribal Air Association, by teleconference, on December 19, 2013. In those teleconferences, the EPA provided background information on the GHG emission guidelines to be developed and a summary of issues being explored by the agency.

In addition, the EPA held a series of listening sessions prior to development of this proposed action. Tribes participated in a session on September 9, 2013 with the state agencies, as well as in a separate session with tribes on September 26, 2013.

6. Industry Representatives

Agency officials have engaged with industry leaders and representatives from trade associations in scores of one-on-one and national meetings. Many meetings occurred at the EPA headquarters and in the EPA's Regional Offices and some were sponsored by stakeholder groups. Because the focus of the standard is on the electricity sector, many of the meetings with industry have been with utilities and industry representatives directly related to the electricity sector. The agency has also met with energy industries such as coal and natural gas interests, as well as companies that offer new technology to prevent or reduce carbon pollution, including companies that have expertise in renewable energy and energy efficiency. Other meetings have been held with representatives of energy intensive industries, such as the iron and steel and aluminum industries to help understand the issues related to large industrial users of electricity.

7. Electric Utility Representatives

Agency officials participated in many meetings with utilities and their associations. The meetings focused on the importance of the utility industry in reducing carbon emissions from power plants. Power plant emissions are central to this rulemaking. The EPA encouraged industry representatives to work with state environmental and energy officers.

The electric utility representatives included private utilities or investor owned utilities. Public utilities and cooperative utilities were also part of in-depth conversations about CAA section 111(d) with EPA officials.

The conversations included meetings with the EPA headquarters and Regional offices. State officials were included in many of the meetings. Meetings with utility associations and groups of utilities were held with key EPA officials. The meetings covered technical, policy, and legal topics of interest and utilities expressed a wide variety of support and concerns about CAA section 111(d).

8. Electricity Grid Operators

The EPA had a number of conversations with the Independent System Operators and Regional Transmission Organizations (ISOs and RTOs) to discuss the rule and issues related to grid operations and reliability. EPA staff met with the ISO/RTO Council on several occasions to collect their ideas. The EPA Regional Offices also met with the ISOs and RTOs in their regions. System operators have offered suggestions in using regional approaches to implement CAA section 111(d) while maintaining reliable, affordable electricity.

9. Representatives From Non-Governmental Organizations

Agency officials engaged with representatives of environmental justice organizations during the outreach effort, for example, we engaged with the National Environmental Justice Advisory Council members in September 2013. The NEJAC is composed of stakeholders, including environmental justice leaders and other

leaders from state and local government and the private sector.

The EPA has also met with a number of environmental groups to provide their ideas on how to reduce carbon pollution from existing power plants using section 111(d) of the CAA.

Many environmental organizations discussed the need for reducing carbon pollution. Meetings were technical, policy and legal in nature and many groups discussed specific state policies that are already in place to reduce carbon pollution in the states.

A number of organizations representing religious groups have reached out to the EPA on several occasions to discuss their concerns and ideas regarding this rule.

Public health groups discussed the need for protection of children's health from harmful air pollution. Doctors and health care providers discussed the link between reducing carbon pollution and air pollution and public health. Consumer groups representing advocates for low income electricity customers discussed the need for affordable electricity. They talked about reducing electricity prices for consumers through energy efficiency and low cost carbon reductions.

10. Labor

EPA senior officials and staff met with a number of labor union representatives about reducing carbon pollution using CAA section 111(d). Those unions included: The United Mine Workers of America; the Sheet Metal, Air, Rail and Transportation Union (SMART); the International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers (IBB); United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry of the United States and Canada; the International Brotherhood of Electrical Workers (IBEW): And the Utility Workers Union of America. In addition, agency leaders met with the Presidents of several unions and the President of the American Federation of Labor-Congress of Industrial Organizations (AFL–CIO) at the AFL–CIO headquarters.

EPA officials, when invited, attended meetings sponsored by labor unions to give presentations and engage in discussions about reducing carbon pollution using CAA section 111(d). These included meetings sponsored by the IBB and the IBEW.

B. Key Messages From Stakeholders

Many stakeholders stated that opportunities exist to reduce the carbon emissions from existing power generation through a wide range of measures, from measures that are implementable via physical changes at the source to those that also are implementable across the broader power generation system. Opinions varied about how broader system measures could factor into programs to reduce carbon pollution. Some stakeholders recommended that system-wide measures be allowed for compliance, but not factored into the carbon improvement goals the EPA establishes, while others recommended that system-wide measures be factored into the goals. Among the arguments and information offered by stakeholders who suggested that states be encouraged to incorporate system-wide measures into their state plans and that EGU operators be encouraged to rely on such measures were examples and discussions of the significant extent to which dispatch, end use energy efficiency and renewable energy had already proven to be successful strategies for reducing EGU CO_2 emissions. Some state and industry representatives favored goals that they described as based on measures implementable only within the facility ''fence line'' (i.e., measures implementable only at the source). Many stakeholders stated that the EPA should not require the state plans to impose on the affected EGUs legal responsibility for the full amount of required CO_2 emissions reductions, and instead, the EPA should authorize the state plans to include requirements on entities other than the affected EGUs that would have the effect of reducing utilization and, therefore, emissions from the affected EGUs.

Views on the form and stringency of the goal or guidelines varied. Some stakeholders preferred a rate-based form of the goal, while others preferred a mass-based form. In addition, some stakeholders recommended that the EPA let the states have the flexibility to either choose among multiple forms of the goals or to set their own goals. With regard to the stringency of the goal, some stakeholders recommended that the stringency of the goals vary by state, to account for differences in state circumstances.

Many stakeholders recognized the value of allowing states flexibility in implementing the goals the EPA establishes. For example, states highlighted the importance of the EPA recognizing existing state and regional programs that address carbon pollution, including market-based programs, and allowing credit for prior accomplishments in reducing CO_2 emissions. Many states and other stakeholders noted the importance of the EPA allowing flexibility in compliance options such that states could use approaches such as demand-side management to attain the goals.

Many stakeholders recommended that states be allowed to develop multi-state programs. It was frequently noted that such regional approaches could offer cost-effective carbon pollution solutions.

There was broad agreement that most states would need more than one year to develop and submit their complete plans to the EPA. For some states, more time is necessary because of the state legislative schedule and/or regulatory process. In some cases, approval of a plan through a state's legislative or regulatory process could take one year or more after the plan has already been developed. Additional time would also allow and encourage multi-state and regional partnerships and programs.

Many stakeholders also supported flexibility in the timing of implementation of the state plans and power sector compliance with the goals in the state plans. Such flexibility, some stakeholders asserted, would accommodate the diverse GHG mitigation potential of states and support more cost-effective approaches to achieving CO_2 reductions.

During the outreach process, some stakeholders raised general concerns that the rulemaking could have a negative impact on jobs and ratepayers. Some stakeholders also expressed concerns about potential adverse effects on electric system reliability. Some stakeholders were concerned that meeting the goals could potentially result in stranded generation assets. To prevent this from occurring, some stakeholders suggested varying the stringency of standards to account for individual state circumstances and variation.

The EPA has given stakeholder input careful consideration during the development of this proposal and, as a result, this proposal includes features that are intended to be responsive to many stakeholder concerns.

C. Key Stakeholder Proposals

During the EPA's public outreach in advance of this proposal, a number of ideas were put forward that are not fully reflected in this proposal. We invite public comment on these ideas, some of which are outlined below.

1. Model Rule on Interstate Emissions Credit Trading and Price Ceiling

Some groups thought that the EPA should put forward a model rule for an interstate emissions credit trading program that could be easily adopted by states who wanted to use such a

program for its plan. One group suggested the model rule should include a provision to allow the state to compensate merchant generators as well as retail rate payers. Another group specified that the model rule would also include a ceiling-price called an alternative compliance payment that would fund state directed clean technology investment. Facilities that face costs that exceed the ceiling price could opt to pay into the fund as a way of complying.

2. Equivalency Tests

One group recommended that state programs be allowed to demonstrate equivalency using one of three tests: Rate-based equivalency via a demonstration that the state program achieves equivalent or better carbon intensity for the regulated sector; mass-based equivalency via a demonstration that the program achieves equal or greater emission reductions relative to what would be achieved by the federal approach; or a market price-based equivalency via a demonstration that the program reflects a carbon price comparable to or greater than the cost-effectiveness benchmark used by the EPA in designing the program. The EPA is proposing a way to demonstrate equivalency and that is discussed in Section VIII of this preamble.

3. Power Plant-Specific Assessment

Other stakeholders suggested that an ''inside the fence'' plant- or unit-specific assessment linked to the availability of control at the source such as heat rate improvements should be considered. They indicated that once plant-specific goals are established based on on-site CO_2 reduction opportunities, the source should have the flexibility to look ''outside the fence'' for the means to achieve the goals, including the use of emissions trading, and averaging.

The EPA invites comment on these suggestions.

D. Consideration of the Range of Existing State Policies and Programs

Across the nation, many states and regions have shown strong leadership in creating and implementing policies and programs that reduce GHG emissions from the power sector while achieving other economic, environmental, and energy benefits. Some of these activities, such as market-based programs and GHG performance standards, directly require GHG emission reductions from EGUs. Others reduce GHG emissions by reducing utilization of fossil fuel-fired EGUs through, for example, renewable portfolio standards (RPS) and energy efficiency resource standards (EERS), which alter the mix of energy supply and reduce energy demand. States have developed their policies and programs with stakeholder input and tailored them to their own circumstances and priorities. Their leadership and experiences provided the EPA with important information about best practices to build upon in this proposed rule. As directed by the Presidential Memorandum, the EPA is, with this proposal to reduce power plant carbon pollution, building on actions already underway in states and the power sector.

1. Market-Based Emission Limits

Nine states actively participate in the Regional Greenhouse Gas Initiative (RGGI), a market-based CO_2 emission reduction program addressing EGUs that was established in 2009.[47] Through RGGI, the participating states are implementing coordinated CO_2 emission budget trading programs. In aggregate, these programs establish an overall limit on allowable CO_2 emissions from affected EGUs in the participating states. Participating states issue CO_2 allowances in an amount up to the number of allowances in each state's annual emission budget. At the end of each three-year compliance period, affected EGUs must submit CO_2 allowances equal to their reported CO_2 emissions. CO_2 allowances may be traded among both regulated and non-regulated parties, creating a market for emission allowances. This market creates a price signal for CO_2 emissions, which factors into the dispatch of affected EGUs. A price signal for CO_2 emissions also allows sources flexibility to make emission reductions where reduction costs are lowest, and encourages innovation in developing emission control strategies.

Approximately 90 percent of CO_2 allowances are distributed by the RGGI participating states through auction.[48] From 2009 through 2012, the nine RGGI states invested auction proceeds of more than $700 million in programs that lower costs for energy consumers and reduce CO_2 emissions.[49] Through 2012, for example, the RGGI states invested approximately $460 million of proceeds into energy efficiency programs.[50] The participating RGGI states estimate that those investments are providing benefits to energy consumers in the region of more than $1.8 billion in lifetime energy savings.[51]

Between 2005, when an agreement to implement RGGI was announced, and 2012, power sector CO_2 emissions in the RGGI participating states fell by more than 40 percent.[52] RGGI was not the primary driver for these reductions but the reductions led RGGI-participating states to later adjust the CO_2 emission limits downward.[53] In January 2014, the participating states lowered the overall allowable CO_2 emission level in 2014 by 45 percent, setting a multi-state CO_2 emission limit for affected EGUs of 91 million short tons of CO_2 in 2014 and 78 million short tons of CO_2 in 2020, more than 50 percent below 2008 levels.[54]

Similarly, California established an economy-wide market-based GHG emissions trading program under the authority of its 2006 Global Warming Solutions Act, which requires the state to reduce its 2020 GHG emissions to 1990 levels.[55] While California's emission trading program, like its state emission limit, is multi-sector in scope, the state projects that the emissions trading program and related complementary measures will reduce power sector GHG emissions to less than 80 million metric tons of CO_2 equivalent by 2025, a 25 percent reduction from 2005 power sector emission levels.[56] Prior to the implementation of the emission trading program, California reports that it reduced CO_2 power sector emissions by 16 percent from 2005 to a 2010–2012

[47] The nine states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

[48] Regional Greenhouse Gas Initiative 2013 Allowance Allocation *http://rggi.org/design/overview/allowance-allocation/2013-allocation.*

[49] Regional Investments of RGGI CO_2 Allowance Proceeds, 2012 (2014), available at *http://www.rggi.org/docs/Documents/2012-Investment-Report.pdf.*

[50] Of the $707 million in auction proceeds invested by RGGI participating states through 2012, 65 percent supported end-use energy efficiency programs. See Regional Greenhouse Gas Initiative, ''Regional Investments of RGGI CO_2 Allowance Proceeds, 2012'' (2014). Available at *http://www.rggi.org/docs/Documents/2012-Investment-Report.pdf.*

[51] Id.

[52] Regional Greenhouse Gas Initiative, Report on Emission Reduction Efforts of the States Participating in the Regional Greenhouse Gas Initiative and Recommendations for Guidelines under Section 111(d) of the Clean Air Act (2013).

[53] The first three-year control period under RGGI, establishing CO_2 emission limits for EGUs, began on January 1, 2009.

[54] RGGI Press Release, January 13, 2014, *http://www.rggi.org/docs/PressReleases/PR011314_AuctionNotice23.pdf.*

[55] State of California Global Warming Solutions Act of 2006, Assembly Bill 32, Chapter *http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf.*

[56] Preliminary California Air Resources Board analyses, based in part on CARB 2008 to 2012 Emissions for Mandatory GHG reporting Summary (2013), cited in Letter to the EPA Administrator, ''States' Roadmap on Reducing Carbon Pollution,'' December 16, 2013. Available at *http://www.georgetownclimate.org/sites/default/files/EPA_Submission_from_States-FinalCompl.pdf.*

averaging period, a reduction of 16 million metric tons of CO_2 equivalent.[57]

2. GHG Performance Standards

Four states, California, New York, Oregon and Washington, have enacted GHG emission standards that impose enforceable emission limits on new and/or expanded electric generating units. For example, since 2012, New York requires new or expanded baseload plants that are greater than 25 Megawatts (MW) to meet an emission rate of either 925 pounds CO_2/Megawatt hour (MWh) (based on output) or 120 pounds of CO_2/Million British Thermal Units (MMBtu) (based on input). Similarly, non-baseload plants in New York of at least 25 MW or larger must meet an emission rate of either 1450 pounds CO_2/MWh (based on output) or 160 pounds of CO_2/MMBtu (based on input).[58]

Three states, California, Oregon and Washington, have enacted GHG emission performance standards that set an emission rate for electricity purchased by electric utilities. In both Oregon and Washington, for example, electric utilities may enter into long term power purchase agreements for baseload power only if the electric generator supplying the power has a CO_2 emission rate of 1,100 pounds of CO_2 per MWh or less.[59]

3. Utility Planning Approaches

Two states, Minnesota and Colorado, have worked collaboratively with their investor-owned utilities to develop multi-pollutant emission reduction plans on a utility-wide basis. This multi-pollutant, collaborative approach enables utilities to determine the least cost way to meet long term and comprehensive energy and environmental goals.

Colorado's Clean Air, Clean Jobs Act of 2010, for example, required Colorado investor-owned utilities with coal plants to develop a multi-pollutant plan to meet existing and reasonably foreseeable federal CAA requirements.[60] The utilities were not required to adopt a specific plan set by the state but were, instead, required to work collaboratively with the Colorado Department of Public Health and Environmental and Colorado Public Utility Commission to develop an acceptable plan. Xcel Energy, Colorado's largest investor-owned utility, submitted a plan that was approved in 2010. With this plan, Xcel Energy is projected to reduce its CO_2 emissions from generation in Colorado by 28 percent by 2020.[61]

4. Renewable Portfolio Standards

More than 25 states have mandatory renewable portfolio standards that require retail electricity suppliers to supply a minimum percentage or amount of their retail electricity load with electricity generated from eligible sources of renewable energy.[62] These standards have been established via utility regulatory commissions, legislatures and citizen ballots and requirements vary from state to state. State RPS typically specify the types of renewable energy, or other energy sources, that qualify for use toward achievement of the standard, and often allow for the use of qualifying renewable energy resources located outside of the state. They reduce utilization of fossil fuel-fired EGUs and, thereby, lead to reductions in GHG emissions by meeting a portion of the demand for electricity through renewable or other energy sources.

In 2007, the Minnesota legislature amended the state's 2001 renewable energy objective and established a renewable energy standard (RES) requiring at least 25 percent of all electricity generated or purchased in Minnesota to come from renewable energy by 2025. The standard sets requirements and timetables, beginning in 2010, that vary based on the provider. For example, in 2011, Xcel Energy had a requirement to generate or purchase 15 percent of its total retail sales from renewable energy while all other utilities had a target of 7 percent of total retail sales. According to the latest Minnesota Department of Commerce report to the legislature on progress, all utilities subject to the standard met it for 2011 and were on track to meet their 2012 goals.[63] The 2012 requirement increased to 18 percent of total retail sales for Xcel Energy and 12 percent for all other utilities.[64] In 2013, the Minnesota legislature expanded the RES with solar incentives and a specific solar energy standard requiring Minnesota utilities to ensure that at least 1.5 percent of their retail electricity sales in 2020 come from solar energy.[65]

The Oregon Renewable Portfolio Standard (RPS) is another example of a state requirement for renewables. Originally enacted in 2007, it requires that all utilities serving Oregon meet a percentage of their retail electricity needs with qualified renewable resources. Like in Minnesota, the percentage varies across utilities with the three largest utilities required to reach five percent from renewable energy sources starting in 2011, 15 percent in 2015, 20 percent in 2020, and 25 percent in 2025. Other electric utilities in the state are required to reach levels of five percent or ten percent by 2025, depending on their size. According to the latest RPS compliance reports submitted by the largest utilities for the state, each had achieved the five percent target as of the end of 2012.[66]

5. Demand-Side Energy Efficiency Programs

Many electric utilities, third-party administrators, and states implement demand-side energy efficiency programs to reduce generation from EGUs by reducing electricity use, including peak demand. When these programs reduce fossil fuel electricity generation, they also reduce CO_2 emissions. Demand-side energy efficiency programs use a variety of energy efficiency measures to target a variety of end uses and are often driven by existing state standards and programs, such as policies requiring utilities to obtain ''all cost-effective energy efficiency'' through long-term integrated resource planning (IRP), renewable portfolio standards (RPS) that include efficiency as a qualifying resource, energy efficiency resource standards (EERS), public benefit funds, and other demand-side planning requirements.

The purposes of demand-side energy efficiency programs vary; goals include to reduce GHG emissions by reducing fossil-fired generation, help states achieve energy savings goals, save energy and money for consumers and improve electricity reliability. They are typically funded through a small fee or surcharge on customer electricity bills, but can also be funded by other sources, such as from RGGI CO_2 allowance auction proceeds mentioned above.

[57] Id.

[58] 6 New York Codes, Rules & Regulations. Part 251 (Adopted June 28, 2012).

[59] OR SB 101 (2000); Washington Revised Code ch.80.80 (2013); Wash SB 6001 (2007).

[60] Colorado Clean Air, Clean Jobs Act, HB1365.

[61] Xcel Energy, Colorado Clean Air-Clean Jobs Plan, available at *http://www.xcelenergy.com/Environment/Doing_Our_Part/Clean_Air_Projects/Colorado_Clean_Air_Clean_Jobs_Plan.*

[62] *http://www.dsireusa.org/.*

[63] Report to the Minnesota Legislature: Progress on Compliance By Electric Utilities With The Minnesota Renewable Energy Objective and the Renewable Energy Standard, Prepared by: The Minnesota Department of Commerce, Division of Energy Resources January 14, 2013; *http://mn.gov/commerce/energy/images/2013RESLegReport.pdf.*

[64] Id.

[65] Minnesota Statutes 2013, Section 216B.1691, Subdivision 2f. Solar Energy Standard *https://www.revisor.mn.gov/statutes/?id=216b.1691.*

[66] Eugene Water Electric Board Oregon Renewable Portfolio Standard 2012 Compliance Report and 2013–2030 Implementation Plan, June 1, 2013. PacifiCorp's Renewable Portfolio Standard Oregon Compliance Report for 2012, May 31, 2013. PGE 2012 Renewable Portfolio Standard Compliance Report, June 1, 2013.

Nationally, total spending on electric ratepayer-funded energy efficiency programs was about $5 billion in 2012.[67] Based on Lawrence Berkeley National Laboratory (LBNL) projections, spending is projected to reach $8.1 billion in 2025.[68]

Electricity savings from energy efficiency programs are also growing. In 2011, electricity savings from these programs totaled approximately 22.9 million MWh, a 22 percent increase from the previous year.[69]

California has been advancing energy efficiency through utility-run demand-side energy efficiency programs for decades and considers energy efficiency ''the bedrock upon which climate policies are built.'' [70] It requires its investor-owned utilities to meet electricity load ''through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible.'' [71] The California Public Utility Commission works with the California Energy Commission to determine the amount of cost-effective reduction potential and establishes efficiency targets. A recent energy efficiency potential study found that, even after years of running programs, California can still tap ''tens of thousands of GWh in potential savings . . . over the next decade.'' [72] Investor-owned utilities use demand-side energy efficiency programs to achieve their targets and currently ''save about 3,000 GW per year, enough savings to power about 600,000 households.'' [73] Between 2010 and 2011, these programs are estimated to have reduced CO_2 by 3.8 million tons.[74]

In Vermont, for example, the Vermont Legislature and the Vermont Public Service Board (PSB) established the first statewide ''energy efficiency utility'' in 1999 to provide energy efficiency services to residences and businesses throughout the state.[75] Vermont law requires that the energy efficiency utility budgets be set at a level to achieve ''all reasonably available, cost-effective energy efficiency'' and then specific energy (kWh) and peak demand (kW) savings levels are negotiated every three years.[76] In 2013, Efficiency Vermont, the PSB-appointed energy efficiency utility, achieved annual savings of 1.66 percent of the state's electricity sales, at a cost of 4.1 cents per kilowatt-hour, lower than the cost of comparable electric supply in the same year, which was 8.4 cents per kWh.[77] Efficiency Vermont projects a net lifetime economic value to Vermont of more than $60 million from the 2013 energy efficiency investments.[78]

6. Energy Efficiency Resource Standards

More than 20 states have energy efficiency resource standards (EERS) that require utilities to save a certain amount of energy each year or cumulatively.[79] They are typically multi-year requirements expressed as a percentage of annual retail electricity sales or as specific electricity savings amounts over a long term period relative to a baseline of retail sales. Over the compliance period, an EERS reduces fossil fuel-fired EGU generation through reductions in electricity demand, thereby reducing CO_2 emissions from the power sector.

In Arizona, for example, the Arizona Corporation Commission (ACC) adopted rules in 2010 requiring all investor-owned utilities to achieve 22 percent cumulative electricity savings by 2020, making it one of the highest standards in the nation.[80] The rule required utilities to achieve 1.25 percent electricity savings in 2011 compared to electricity sales in the previous year, ramping up the savings each year until 2020 according to a designated timetable.[81] In 2012, for example, investor-owned utilities were required to achieve energy savings equivalent to 1.75 percent of the 2011 sales, leading to a cumulative savings requirement of 3 percent by the end of 2012 (an average of 1.5% annually over the 2 year period).[82] Utilities can meet the energy savings requirements through a variety of means, including cost-effective energy efficiency programs, as well as load management and demand response programs.[83] Arizona Public Service Company (APS), the largest utility in Arizona, achieved cumulative energy savings equivalent to 3.2 percent of retail sales from 2011 to 2012, exceeding the 3 percent savings target, and reported a net benefit to consumers of more than $200 million for the year 2012 alone.[84]

E. Conclusions

States have taken a leadership role in mitigating GHG emissions and have demonstrated the potential for national application of a number of approaches. Throughout the development of this proposed rule, the EPA considered the states' experiences and lessons learned regarding the design and implementation of successful GHG mitigation programs. The agency also fully considered input from stakeholders during the development of this proposed rulemaking.

Considering all input from stakeholders, the agency recognizes that the most cost-effective approach to reducing GHG emissions from the power sector under CAA section 111(d) is to follow the lead of numerous states and not only to identify improvements in the efficiency of fossil fuel-fired EGUs as a component of the BSER, but also include in the BSER determination the EGU-emissions-reduction opportunities that states have already demonstrated to be successful in relying on lower- and zero-emitting generation and reduced electricity demand.

CAA section 111(d) sets up a partnership between the EPA and the states. In the context of that partnership, the EPA recognizes the importance of each state having the flexibility to design a cost-effective program tailored to its own specific circumstances. The agency also recognizes, as many states

[67] Consortium for Energy Efficiency Annual Industry Report: 2013 State of the Efficiency Program Industry—Budgets, Expenditures and Impacts, 2014.

[68] Lawrence Berkeley National Laboratory (LBNL) The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025 (*http://emp.lbl.gov/sites/all/files/lbnl-5803e.pdf*).

[69] American Council for an Energy Efficient Economy (ACEEE) 2013 State Scorecard *http://www.aceee.org/sites/default/files/publications/researchreports/e13k.pdf.*

[70] December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy.

[71] Cal Pub. Utility Code § 454.5 (a)(9)(C).

[72] Cited in December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy.

[73] Id.

[74] Id.

[75] State of Vermont Public Service Board, Energy Efficiency Utility Creation and Structure. *http://psb.vermont.gov/utilityindustries/eeu/generalinfo/creationandstructure.*

[76] Vermont Statute, Title 30: Public Service, 30 V.S.A. § 209 (d)3(B). *http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00209.*

[77] Efficiency Vermont Savings Claim Summary 2013, Reported to the Vermont Public Service Board and to the Vermont Public Service Department, 2014, *https://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_summaries/2013_savingsclaim_summary.pdf.*

[78] Id.

[79] State Energy Efficiency Resource Standards: Policy Design, Status, and Impacts, DC Steinberg, O. Zinaman, NREL Technical Report NREL/TP–6A20–61023, April 2014.

[80] Arizona Corporation Commission, Docket RE–OOOOOC–09–0427, August 2010. Available at *http://images.edocket.azcc.gov/docketpdf/0000116125.pdf.*

[81] Id.

[82] Arizona Corporation Commission, Docket RE–OOOOOC–09–0427, August 2010. Available at *http://images.edocket.azcc.gov/docketpdf/0000116125.pdf.*

[83] Id.

[84] Arizona Public Service Company 2012 Demand Side Management Annual Progress Report, March 1, 2013 Web site, *http://www.aps.com/en/ourcompany/aboutus/energyefficiency/Pages/home.aspx.*

have, the value of regional planning in designing approaches to achieve cost-effective GHG reductions. To support state flexibility and encourage multi-state coordination in the development of multi-state and regional programs and policies, the EPA recognizes that flexibility in both the timing of plan submittal and the timing of CO_2 emission reductions will be necessary.

IV. Rule Requirements and Legal Basis

A. Summary of Rule Requirements

The EPA is proposing emission guidelines for each state to use in developing plans to address greenhouse gas emissions from existing fossil fuel-fired electric generating units. The emission guidelines are based on the EPA's determination of the ''best system of emission reduction . . . adequately demonstrated'' (BSER) and include state-specific goals, general approvability criteria for state plans, requirements for state plan components, and requirements for the process and timing for state plan submittal and compliance.

Under CAA section 111(d), the states must establish standards of performance that reflect the degree of emission limitation achievable through the application of the ''best system of emission reduction'' that, taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements, the Administrator determines has been adequately demonstrated. Consistent with CAA section 111(d), the EPA is proposing state-specific goals that reflect the EPA's calculation of the BSER.

Under CAA section 111(d), each state must develop, adopt, and then submit its plan to the EPA. To do so, the state would determine, and include in its plan, an emission performance level that is equivalent to the state-specific CO_2 goal in the emission guidelines. As part of determining this level, the state would decide whether to adopt the rate-based form of the goal established by the EPA or translate the rate-based goal to a mass-based goal. The state would then establish a standard of performance or set of standards of performance (known as emission standards under the existing CAA section 111(d) framework regulations), along with implementing and enforcing measures, that will achieve a level of emission performance that equals or exceeds the level specified in the state plan.

The EPA is proposing to determine the BSER as the combination of emission rate improvements and limitations on overall emissions at affected EGUs that can be accomplished through any combination of one or more measures from the following four sets of measures or building blocks:

1. Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements.
2. Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including natural gas combined cycle (NGCC) units that are under construction).
3. Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.
4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

The EPA has reviewed information about the current and recent performance of affected EGUs and states' implementation of programs that reduce CO_2 emissions from these sources. Based on our analysis of that information, the proposed state goals reflect the following stringency of application of the measures in each of the building blocks: Block 1, improving average heat rate of coal-fired steam EGUs by six percent; block 2, displacing coal-fired steam and oil/gas-fired steam generation in each state by increasing generation from existing NGCC capacity in that state toward a 70 percent target utilization rate; block 3, including the projected amounts of generation achievable by completing all nuclear units currently under construction, avoiding retirement of about six percent of existing nuclear capacity, and increasing renewable electric generating capacity over time through the use of state-level renewable generation targets consistent with renewable generation portfolio standards that have been established by states in the same region; and block 4, increasing state demand-side energy efficiency efforts to reach 1.5 percent annual electricity savings in the 2020–2029 period.

Based on the EPA's application of the BSER to each state, the EPA is proposing to establish, as part of the emission guidelines, state-specific goals, expressed as average emission rates for fossil fuel-fired EGUs. Each state's goals comprise the EPA's determination of the emission limitation achievable through application of the BSER in that state. For each state, the EPA is proposing an interim goal for the phase-in period from 2020 to 2029 and the final goal that applies beginning in 2030. The proposed goals for each state are listed in Section VII, below. The EPA is proposing that measures that a state takes after the date of this proposal, and that result in CO_2 emission reductions during the plan period, would apply toward achievement of the state's CO_2 goal.

The EPA is further proposing, as part of the plan guidelines, timetables for states to submit their plans. The agency expects to finalize this rulemaking by June 2015, and we are proposing to require that each state submit its plan to the EPA by June 30, 2016. However, if a state needs additional time to submit a complete plan, the state must submit an initial plan by June 30, 2016, that documents the reasons why more time is needed to submit a complete plan and includes commitments to take concrete steps that will ensure that the state will submit a complete plan by June 30, 2017, or June 30, 2018, as appropriate. If such a state is developing a plan limited in geographical scope to the individual state, then the state would have until June 30, 2017, to submit a complete plan. A state that is developing a plan that includes a multi-state approach would have until June 30, 2018, to submit a complete plan.

The EPA is further proposing, as part of the emission guidelines, to allow states the option of translating the EPA-determined goal, which will be rate-based, to a mass-based goal. For states participating in a multi-state approach, the individual state performance goals in the emission guidelines would be replaced with an equivalent multi-state performance goal. The EPA is also proposing that in their plans, whether single state or multi-state, states may not adjust the stringency of the goals set by the EPA.

Under CAA section 111(d)(1) and the implementing regulations, with the state emission performance level in place, the state must adopt a state plan that establishes a standard of performance or set of standards of performance, along with implementing and enforcing measures, that will achieve that emission performance level. The EPA is further proposing, as part of the guidelines, to authorize the state to submit either of two types of measures to achieve the performance level: (1) A set of measures that we refer to as ''portfolio'' measures, which include a combination of emission limitations that apply directly to the affected sources and other measures that have the effect of limiting generation by, and therefore emissions from, the affected sources; or (2) solely emission limitations that apply directly to the affected sources.

The EPA is also proposing, as part of the plan guidelines, that a complete state plan include the following twelve components:

- Identification of affected entities
- Description of plan approach and geographic scope
- Identification of state emission performance level
- Demonstration that plan is projected to achieve emission performance level
- Identification of emissions standards
- Demonstration that each emissions standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable
- Identification of monitoring, reporting, and recordkeeping requirements
- Description of state reporting
- Identification of milestones
- Identification of backstop measures
- Certification of hearing on state plan
- Supporting material

The EPA is also proposing, as part of its emission guidelines, that plan approvability be based on four general criteria: (1) Enforceable measures that reduce EGU CO_2 emissions; (2) projected achievement of emission performance equivalent to the goals established by the EPA, on a timeline equivalent to that in the emission guidelines; (3) quantifiable and verifiable emission reductions; and (4) a process for reporting on plan implementation, progress toward achieving CO_2 goals, and implementation of corrective actions, if necessary.

The EPA is also proposing, as part of its plan guidelines, requirements for the process and timing for demonstrating achievement of the required emission performance level, including performance and emission milestones. The proposed option would require each state to achieve its ultimate CO_2 emission performance level by 2030 and, in addition, provide an initial, phase-in compliance period of up to 10 years, from 2020 up to 2029, for a state and/or other responsible parties to comply with the emission performance level in the state plan. A state would need to meet its interim 2020–2029 CO_2 emission performance level on average over the 10-year phase-in compliance period, achieve its final CO_2 emission performance level by 2030, and maintain it thereafter.

If a state with affected EGUs does not submit a plan or if the EPA does not approve a state's plan, then under CAA section 111(d)(2)(A), the EPA must establish a plan for that state. A state that has no affected EGUs must document this in a formal letter submitted to the EPA by June 30, 2016. In the case of a tribe that has one or more affected EGUs in its area of Indian country,[85] the tribe would have the opportunity, but not the obligation, to establish a CO_2 emission performance standard and a CAA section 111(d) plan for its area of Indian country. If it determines that such a plan is necessary or appropriate, the EPA has the responsibility to establish CAA section 111(d) plans for areas of Indian country where affected sources are located unless a tribe on whose lands an affected source (or sources) is located seeks and obtains authority from the EPA to establish a plan itself, pursuant to the Tribal Authority Rule.

B. Summary of Legal Basis

This proposed action is consistent with the requirements of CAA section 111(d) and the implementing regulations. As an initial matter, the EPA reasonably interprets the provisions identifying which air pollutants are covered under CAA section 111(d) to authorize the EPA to regulate CO_2 from fossil fuel-fired EGUs. In addition, the EPA recognizes that CAA section 111(d) applies to sources that, if they were new sources, would be covered under a CAA section 111(b) rule. The EPA intends to complete two CAA section 111(b) rulemakings regulating CO_2 from new fossil fuel-fired EGUs and from modified and reconstructed fossil fuel-fired EGUs before it finalizes this rulemaking, and either of those section 111(b) rulemakings will provide the requisite predicate for this rulemaking.

A key step in promulgating requirements under CAA section 111(d) is determining the ''best system of emission reduction . . . adequately demonstrated'' (BSER). In promulgating the implementing regulations, the EPA explicitly stated that it is authorized to determine the BSER;[86] accordingly, in this rulemaking, the EPA is determining the BSER.

The EPA is proposing two alternative BSER for fossil fuel-fired EGUs, each of which is based on methods that have already been employed for reducing emissions of air pollutants, including, in some cases, CO_2, from these sources. The first identifies the combination of the four building blocks as the BSER. These include operational improvements and equipment upgrades that the coal-fired steam-generating EGUs in the state may undertake to improve their heat rate (building block 1) and increases in, or retention of, zero- or low-emitting generation, as well as measures to reduce demand for generation, all of which, taken together, displace, or avoid the need for, generation from the affected EGUs (building blocks 2, 3, and 4). All of these measures are components of a ''system of emission reduction'' for the affected EGUs because they either improve the carbon intensity of the affected EGUs in generating electricity or, because of the integrated nature of the electricity system and the fungibility of electricity, they displace or avoid the need for generation from those sources and thereby reduce the emissions from those sources. Moreover, those measures may be undertaken by the affected EGUs themselves and, in the case of building blocks 2, 3, and 4, they may be required by the states.

Further, these measures meet the criteria in CAA section 111(a)(1) and the caselaw as the ''best'' system of emission reduction because, among other things, they achieve the appropriate level of reductions, they are of reasonable cost, and they encourage technological development that is important to achieving further emission reductions. Moreover, the measures in each of the building blocks are ''adequately demonstrated'' because they are each well-established in numerous states, and many of them have already been relied on to reduce GHGs and other air pollutants from fossil fuel-fired EGUs. It should be emphasized that these measures are consistent with current trends in the electricity sector.

For the alternative approach for the BSER, the EPA is identifying the ''system of emission reduction'' as including, in addition to building block 1, the reduction of affected fossil fuel-fired EGUs' mass emissions achievable through reductions in generation of specified amounts from those EGUs. Under this approach, the measures in building blocks 2, 3, and 4 would not be components of the system of emission reduction, but instead would serve as bases for quantifying the reduction in emissions resulting from the reduction in generation at affected EGUs. In light of the available sources of replacement generation through the measures in the building blocks, this approach would also meet the criteria for being the ''best'' system that is ''adequately demonstrated'' because of the emission reductions it would

[85] The EPA is aware of at least four affected EGUs located in Indian country: Two on Navajo lands, the Navajo Generating Station and the Four Corners Generating Station; one on Ute lands, the Bonanza Generating Station; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.

[86] The EPA is not re-opening that interpretation in this rulemaking.

achieve, its reasonable cost, and its promotion of technological development, as well as the fact that the reliability of the electricity system would be maintained.

After determining the BSER, the EPA is authorized under the implementing regulations, as an integral component to setting emission guidelines, to apply the BSER and determine the resulting emission limitation. The EPA is proposing to apply the BSER to the affected EGUs on a statewide basis. In this rulemaking, the EPA terms the resulting emission limitation the state goal.

With the promulgation of the emission guidelines, each state must develop a plan to achieve an emission performance level that corresponds to the state goal. The state plans must establish standards of performance for the affected EGUs and include measures that implement and enforce those standards. Based on requests from stakeholders, the EPA is proposing that states be authorized to submit state plans that do not impose legal responsibility on the affected EGUs for the entirety of the emission performance level, but instead, by adopting what this preamble refers to as a ''portfolio approach,'' impose requirements on other affected entities (e.g., renewable energy and demand-side energy efficiency measures) that would reduce CO_2 emissions from the affected EGUs.

It should be noted that an important aspect of the BSER for affected EGUs is that the EPA is proposing to apply it on a statewide basis. The statewide approach also underlies the required emission performance level, which, as noted, is based on the application of the BSER to a state's affected EGUs, and which the suite of measures in the state plan, including the emission standards for the affected EGUs, must achieve overall. The state has flexibility in assigning the emission performance obligations to its affected EGUs, in the form of standards of performance—and, for the portfolio approach, in imposing requirements on other entities—as long as, again, the required emission performance level is met.

This state-wide approach both harnesses the efficiencies of emission reduction opportunities in the interconnected electricity system and is fully consistent with the principles of federalism that underlie the Clean Air Act generally and CAA section 111(d) particularly. That is, this provision achieves the emission performance requirements through the vehicle of a state plan, and provides each state significant flexibility to take local circumstances and state policy goals into account in determining how to reduce emissions from its affected sources, as long as the plan meets minimum federal requirements. This state-wide approach, and the standards of performance for the affected EGUs that the states will establish through the state-plan process, are consistent with the applicable CAA section 111 provisions.

A state has discretion in determining the measures in its plans. The state may adopt measures that assure the achievement of the required emission performance level, and is not limited to the measures that the EPA identifies as part of the BSER. By the same token, the affected EGUs, to comply with the applicable standards of performance in the state plan, may rely on any efficacious means of emission reduction, regardless of whether the EPA identifies those measures as part of the BSER.

In this rulemaking, the EPA proposes reasonable deadlines for state plan submission and the EPA's action. The proposed deadline for the EPA's action on state plan submittals varies from that in the implementing regulations, and the EPA is proposing to revise that provision in the regulations accordingly. Under CAA section 111(d)(2), the state plans must be ''satisfactory'' for the EPA to approve them, and in this rulemaking, the EPA is proposing the criteria that the state plans must meet under that requirement.

The EPA discusses its legal interpretation in more detail in other parts of this preamble and discusses certain issues in more detail in the Legal Memorandum included in the docket for this rulemaking. The EPA solicits comment on all aspects of its legal interpretations, including the discussion in the Legal Memorandum.

V. Authority To Regulate Carbon Dioxide and EGUs, Affected Sources, Treatment of Categories

A. Authority To Regulate Carbon Dioxide

The EPA has the authority to regulate, under CAA section 111(d), CO_2 emissions from EGUs, under the Agency's construction of the ambiguous provisions in CAA section 111(d)(1)(A)(i) that identify the air pollutants subject to CAA section 111(d). The ambiguities stem from apparent drafting errors that occurred during enactment of the 1990 CAA Amendments, which revised section 111(d).

During the 1990 CAA Amendments, the House of Representatives and the Senate each passed an amendment to CAA section 111(d)(1)(A)(i). The two amendments differed from each other, and were not reconciled during the Conference Committee and, as a result, both were enacted into law. As amended by the Senate, the pertinent language of CAA section 111(d)(1) would exclude the regulation of any pollutant which is ''included on a list published under [CAA section] 112(b).'' [87] As amended by the House, the pertinent language in CAA section 111(d)(1) would exclude the regulation of any pollutant which is ''emitted from a source category which is regulated under section 112.'' [88] The two versions conflict with each other and thus are ambiguous. Under these circumstances, the EPA may reasonably construe the provision to authorize the regulation of GHGs under CAA section 111(d).

It should be noted that the U.S. Supreme Court's holding in *American Electric Power Co.* v. *Connecticut,* 131 S. Ct. 2527, 2537–38 (2011), that ''the Clean Air Act and the EPA actions it authorizes displace any federal common law right to seek abatement of carbon-dioxide emissions from fossil fuel-fired power plants'' was premised on the Court's understanding that CAA section 111, including CAA section 111(d), applies to carbon dioxide emissions from those sources.

We discuss this issue in more detail in the Legal Memorandum.

B. Authority To Regulate EGUs

Before the EPA finalizes this CAA section 111(d) rule, the EPA will finalize a CAA section 111(b) rulemaking regulating CO_2 emissions from new EGUs, which will provide the requisite predicate for applicability of CAA section 111(d).

CAA section 111(d)(1) requires the EPA to promulgate regulations under which states must submit state plans regulating ''any existing source'' of certain pollutants ''to which a standard of performance would apply if such existing source were a new source.'' A ''new source'' is ''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 [CAA section 111] which will be applicable to such source.'' It should be noted that these provisions make clear that a ''new source'' includes one that undertakes either new construction or a modification. It should also be noted

[87] Public Law 101–549, § 302(a), 104 Stat. at 2574 (Nov. 15, 1990).

[88] Public Law 101–549, § 108(g), 104 Stat. at 2467 (Nov. 15, 1990).

that the EPA's implementing regulations define ''construction'' to include ''reconstruction,'' which the implementing regulations go on to define as the replacement of components of an existing facility to an extent that (i) 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 (ii) it is technologically and economically feasible to meet the applicable standards.

Under CAA section 111(d)(1), in order for existing sources to become subject to that provision, the EPA must promulgate standards of performance under CAA section 111(b) to which, if the existing sources were new sources, they would be subject. Those standards of performance may include ones for sources that undertake new construction, modifications, or reconstructions.

The EPA is in the process of promulgating two rulemakings under CAA section 111(b) for CO_2 emissions from affected sources. The EPA proposed the first, which applies to affected sources undertaking new constructions, by notice dated January 8, 2014, which we refer to as the January 2014 Proposal. The EPA is proposing the second, which applies to affected sources undertaking modifications or reconstructions, concurrently with this CAA section 111(d) proposal. The EPA will complete one or both of these CAA section 111(b) rulemakings before or concurrently with this CAA section 111(d) rulemaking, which will provide the requisite predicate for applicability of CAA section 111(d).[89]

C. Affected Sources

The EPA is proposing that, for the emission guidelines, an affected EGU is any fossil fuel-fired EGU that was in operation or had commenced construction as of January 8, 2014, and is therefore an ''existing source'' for purposes of CAA section 111, and that in all other respects would meet the applicability criteria for coverage under the proposed GHG standards for new fossil fuel-fired EGUs (79 FR 1430; January 8, 2014).

The January 8, 2014 proposed GHG standards for new EGUs generally define an affected EGU as any boiler, integrated gasification combined cycle (IGCC), or combustion turbine (in either simple cycle or combined cycle configuration) that (1) is capable of combusting at least 250 million Btu per hour; (2) combusts fossil fuel for more than 10 percent of its total annual heat input (stationary combustion turbines have an additional criteria that they combust over 90 percent natural gas); (3) sells the greater of 219,000 MWh per year and one-third of its potential electrical output to a utility distribution system; and (4) was not in operation or under construction as of January 8, 2014 (the date the proposed GHG standards of performance for new EGUs were published in the **Federal Register**). The minimum fossil fuel consumption condition applies over any consecutive three-year period (or as long as the unit has been in operation, if less). The minimum electricity sales condition applies on an annual basis for boilers and IGCC facilities and over rolling three-year periods for combustion turbines (or as long as the unit has been in operation, if less).

The rationale for this proposal concerning applicability is the same as that for the January 8, 2014 proposal, sections V.A–B. See 79 FR at 1,459/1–1,461/2. We incorporate that discussion by reference here.

D. Implications for Tribes and U.S. Territories

As noted in Section II.D of this preamble, although affected EGUs located in Indian country operate as part of the interconnected system of electricity production and distribution, affected EGUs located in Indian country within a state's borders would not be encompassed within the state's CAA section 111(d) plan. The EPA is aware of four potentially affected power plants located in Indian country: The South Point Energy Center, on Fort Mojave tribal lands within Arizona; the Navajo Generating Station, on Navajo tribal lands within Arizona; the Four Corners Power Plant, on Navajo tribal lands within New Mexico; and the Bonanza Power Plant, on Ute tribal lands within Utah. The South Point facility is an NGCC power plant, and the Navajo, Four Corners, and Bonanza facilities are coal-fired power plants. The operators and co-owners of these four facilities include investor-owned utilities, cooperative utilities, public power agencies, and independent power producers, most of which also co-own potentially affected EGUs within state jurisdictions. We are not aware of any potentially affected EGUs that are owned or operated by tribal entities. If it determines that such a plan is necessary or appropriate, the EPA has the responsibility to establish CAA section 111(d) plans for areas of Indian country where affected sources are located unless a tribe on whose lands an affected source (or sources) is located seeks and obtains authority from the EPA to establish a plan itself, pursuant to the Tribal Authority Rule.[90] The EPA intends to publish a supplemental proposal to establish emission performance goals (if it determines that such action is necessary or appropriate) covering the four potentially affected power plants identified above, as well as any subsequently identified similarly situated power plants, and also to proposed goals for U.S. territories with affected EGUs. The EPA intends to take final action on that proposal by June 2015. If a tribe does seek and obtain the necessary authority to establish a plan itself, it is the EPA's intention that the tribe would have flexibility to develop a plan tailored to its circumstances, in the same manner as a state, to meet CO_2 emission performance goals that would be established by the EPA based on application of the BSER to that area of Indian country. The EPA is aware of actions that have been taken or are being taken by some sources in tribal areas or territories and will be mindful of these actions in considering establishment of a plan.

The EPA invites comment on whether a tribe wishing to develop and implement a CAA section 111(d) plan should have the option of including the EGUs located in its area of Indian country in a multi-jurisdictional plan with one or more states (i.e., treating the tribal lands as an additional state).

If the EPA develops one or more CAA section 111(d) federal plans for areas of Indian country with affected EGUs, we are likewise currently considering doing so on a multi-jurisdictional basis in coordination with nearby states developing section 111(d) state plans. The EPA solicits comment on such an approach for a federal plan.

At this time, the EPA is not proposing CO_2 emission performance goals for areas of Indian country containing potentially affected EGUs. We do plan to establish such goals in the future, to be addressed through either tribal or federal plans, as discussed above. The EPA notes that some present and planned actions being taken to reduce criteria pollutants from EGUs in Indian country will result in significant CO_2 emission reductions relative to emissions in the 2012 baseline period used in computing the state CO_2

[89] In the past, the EPA has issued standards of performance under section 111(b) and emission guidelines under section 111(d) simultaneously. *See* ''Standards of Performance for new Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills—Final Rule,'' 61 FR 9905 (March 12, 1996).

[90] See 40 CFR 49.1 to 49.11.

performance goals in this proposal.[91] We invite comment on how the BSER should be applied to potentially affected EGUs in Indian country. We particularly invite comment on data sources for setting renewable energy and demand-side energy efficiency targets.

The state-specific goals that the EPA is proposing are based on the collection of affected EGUs located within that state. In setting goals specific to an area of Indian country, the EPA proposes to base the goals on the collection of affected EGUs located within that area of Indian country. We request comment on this approach.

E. Combined Categories and Codification in the Code of Federal Regulations

In this rulemaking, the EPA is soliciting comment on combining the two existing categories for the affected EGUs into a single category for purposes of facilitating emission trading among sources in both categories. The EPA is also proposing codifying all of the proposed requirements for the affected EGUs in a new subpart UUUU of 40 CFR part 60.

As discussed in the January 8, 2014 proposal for the CAA section 111(b) standards for GHG emissions from EGUs, in 1971 the EPA listed fossil fuel-fired steam generating boilers as a new category subject to section 111 rulemaking, and in 1979 the EPA listed fossil fuel-fired combustion turbines as a new category subject to the CAA section 111 rulemaking. In the ensuing years, the EPA has promulgated standards of performance for the two categories, and codified those standards, at various times, in 40 CFR part 60 subparts D, Da, GG, and KKKK. In the 2014 proposal, the EPA proposed separate standards of performance for sources in the two categories and proposed codifying the standards in the same Da and KKKK subparts that currently contain the standards of performance for conventional pollutants from those sources. In addition, the EPA co-proposed combining the two categories into a single category solely for purposes of the CO_2 emissions from new construction of affected EGUs, and codifying the proposed requirements in a new 40 CFR part 60 subpart TTTT. The EPA solicited comment on whether combining the categories for new sources is necessary in order to combine the categories for existing sources.

In the present rulemaking, the EPA is proposing emission guidelines for the two categories and is soliciting comment on combining the two categories into a single category for purposes of the CO_2 emissions from existing affected EGUs. The EPA solicits comment on whether combining the two categories would offer additional flexibility, for example, by facilitating implementation of CO_2 mitigation measures, such as shifting generation from higher to lower-carbon intensity generation among existing sources (e.g., shifting from boilers to NGCC units) or facilitating emissions trading among sources. Because the two categories are pre-existing and the EPA would not be subjecting any additional sources to regulation, the combined category would not be considered a new category that the EPA must list under CAA section 111(b)(1)(A). As a result, this proposal does not list a new category under section 111(a)(1)(A), nor does this proposal revise either of the two source categories—steam-generating boilers and combustion turbines—that the EPA has already listed under that provision. Thus, the EPA would not be required to make a finding that the combined category causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

In addition, the EPA is proposing to create a new subpart UUUU and to include all GHG emission guidelines for the affected sources—utility boilers and IGCC units as well as natural gas-fired stationary combustion turbines—in that newly created subpart. We believe that combining the emission guidelines for affected sources into a new subpart UUUU is appropriate because the emission guidelines the EPA is establishing do not vary by type of source. Accordingly, the EPA is not proposing to codify any of the requirements of this rulemaking in subparts Da or KKKK.

VI. Building Blocks for Setting State Goals and the Best System of Emission Reduction

A. Introduction

Based on the experiences of states and the industry and the EPA's outreach with stakeholders as described above, the EPA has identified multiple measures currently in use for achieving CO_2 emission reductions from existing fossil fuel-fired EGUs. For purposes of determining the ''best system of emission reduction . . . adequately demonstrated'' (BSER) and developing state emission performance goals, we have screened the measures and have found that they support two alternative formulations for the BSER. We are grouping the measures that we are proposing to consider further at this time into four categories, which we call ''building blocks.'' We provide an overview of these building blocks in Section VI.B and more detailed discussion of each block in Section VI.C. In Section VI.D we discuss possible combinations of the building blocks, and in Section VI.E, we explain why as a legal matter all four building blocks, taken together, support the BSER, which in turn serves as the basis for the standards of performance that the states must include in their state plans, as CAA section 111(d) requires.

As discussed in Section III of this preamble, we are mindful of numerous and varied stakeholder concerns, including the need to achieve meaningful CO_2 emission reductions at the affected facilities and to recognize and take advantage of the progress already made by existing programs. Like stakeholders, we are attentive to the need to maintain electricity system reliability and to minimize adverse impacts on electricity and fuel prices and on assets that have already been improved by installation of controls for other kinds of pollution. Many of these considerations align with our approach to determining the BSER, as discussed more in Section VII, and we consider several of these to be key principles in this application. As discussed in Sections VII and VIII, we acknowledge and appreciate the advantages of allowing and promoting flexibility for states in crafting their programs. We recognize the knowledge that states have about their specific situations and their ability to evaluate and leverage existing and new capacity and programs to ultimately reduce EGU CO_2 emissions.

Similarly, we recognize and appreciate that states operate with differing circumstances and policy preferences. For example, states have differing access to specific fuel types, and the variety of types of EGUs operating in different states is broad and significant. States are part of assorted EGU dispatch systems and vary in the amounts of electricity that they import and export. For these reasons, we also recognize and appreciate the value in allowing and promoting multi-state reduction strategies. Some states already participate in a multi-state program that reduces CO_2 emissions, the RGGI, and we have noted the success of that program for those states.

[91] For example, a plan currently being implemented at the Four Corners plant to satisfy regional haze requirements calls for reduction of NOx emissions to be achieved in part by shutting down a portion of the plant's generating capacity, and a similar plan has been proposed for the Navajo plant. See 78 FR 62509 (October 22, 2013).

Another key consideration in determining the BSER, as discussed more in the following sections, is the relationship between the timing of measures and their effectiveness in limiting emissions. For example, actions that can occur in the near term, such as improvements to individual EGU heat rates, may fail to achieve the cumulative emission reductions that sustained implementation of other actions, such as demand-side energy efficiency programs, may achieve over time.

B. Building Blocks for the Best System of Emission Reduction

This subsection summarizes the EPA's analytic approach to determining the best system of emission reduction (BSER) for CO_2 emissions from existing EGUs. Later subsections discuss particular measures and how they form the basis of the BSER.[92]

1. Overview of Approach

In considering the appropriate scope of the proposed BSER, the EPA evaluated three basic groupings of strategies for reducing CO_2 emission from EGUs: (i) Reductions achievable through improvements in individual EGUs' emission rates (referred to throughout this preamble as ''building block 1''); (ii) EGU CO_2 emissions reductions achievable through re-dispatch from affected steam EGUs to affected NGCC units (''building block 2''); and (iii) EGU CO_2 emissions reductions achievable by meeting demand for electricity or electricity services through expanded use of low- or zero-carbon generating capacity (''building block 3'') and through expanded use of demand-side energy efficiency (''building block 4''). While the first grouping plays the same role in each of our two formulations of the BSER, the second and third groupings play different roles: In the first formulation they constitute components of the BSER, and in the second formulation they serve as the basis for why a component of that formulation of the BSER—reduced utilization of the higher-emitting affected EGUs—is adequately demonstrated.

As described in the remainder of this section, the EPA concluded that while certain strategies within the first grouping clearly should be part of the BSER, it was not appropriate to limit consideration of the BSER to this first grouping, for several reasons. First, we determined that some strategies available in the other two groupings can support reduced CO_2 emissions from the fossil fuel-fired EGUs by significant amounts and at lower costs than some of the strategies in the first grouping. Second, we observed that strategies in all three groupings were already being pursued by states and sources taking advantage of the integrated nature of the electricity system, at least in part for the purpose of reducing CO_2 emissions. Third, we were concerned that if measures from the first grouping that improve heat rates at coal-fired steam EGUs were implemented in isolation, without additional measures that encourage substitution of less carbon-intensive ways of providing electricity services for more carbon-intensive generation, the resulting increased efficiency of coal-fired steam units would provide incentives to operate those EGUs more, leading to smaller overall reductions in CO_2 emissions.[93] These factors reinforced the appropriateness of our considering strategies from all three groupings for purposes of determining the BSER.

2. CO_2 Reductions Achievable Through Improvements in Individual EGUs' Emission Rates

The first grouping of CO_2 emission reduction options that the EPA evaluated as potential options for the BSER consists of measures that can reduce individual EGUs' CO_2 emission rates (i.e., the amount of CO_2 emitted per unit of electricity[94] output). These measures included improving the efficiency with which EGUs convert fuel heat input to electricity output (i.e., heat rate improvements), applying carbon capture and storage (CCS) technology, and substituting lower-carbon fuels such as natural gas for higher-carbon fuels such as coal (i.e., natural gas co-firing or conversion).

Our assessment of heat rate improvements showed that these measures would achieve CO_2 emission reductions at low costs, although compared to other measures, the available reductions were relatively limited in quantity.[95] Specifically, our analysis indicated that average CO_2 emission reductions of 1.3 to 6.7 percent could be achieved by coal-fired steam EGUs through adoption of best practices, and that additional average reductions of up to four percent could be achieved through equipment upgrades.[96] Heat rate improvements pay for themselves at least in part through reductions in fuel costs, generally making this a relatively inexpensive approach for reducing CO_2 emissions. We estimated that CO_2 reductions of between four and six percent from overall heat rate improvements could be achieved on average across the nation's fleet of coal-fired steam EGUs for net costs in a range of $6 to $12 per metric ton.[97]

The EPA also examined application of CCS technology at existing EGUs. CCS offers the technical potential for CO_2 emission reductions of over 90 percent, or smaller percentages in partial applications. In the recently proposed Carbon Pollution Standards for new fossil fuel-fired EGUs (79 FR 1430), we found that partial CCS was adequately demonstrated for new fossil fuel-fired steam EGUs and integrated gasification

[92] The EPA is aware of the potential that one or more facilities involved in programs mentioned or relied on in this proposal may have received some form of assistance under the Energy Policy Act of 2005 (EPAct). Section 402 (i) of the EPAct (codified at 42 U.S.C. section 15962(i)) states:

''No technology, or level of emission reduction, solely by reason of the use of the technology, or the achievement of the emission reduction, by 1 or more facilities receiving assistance under this Act, shall be considered to be—(1) adequately demonstrated for purposes of section 111 of the Clean Air Act (42 U.S.C. 7411)[.]''

In a February 26, 2014 Notice of Data Availability, the EPA proposed to give this provision its natural meaning: the term ''solely'' modifies all of the provisions, so that any ''adequately demonstrated'' finding by the EPA could not be based solely upon technology, level of emission reduction, or achievement of the emission reduction by a facility (or facilities) receiving assistance. The EPA proposes the same interpretation here. The EPA further believes that its proposed determination of the ''best system of emission reduction . . . adequately demonstrated'' does not depend exclusively on technology, level of emission reduction, or achievement of emission reduction from facilities receiving EPAct assistance, given the myriad number of technologies and emission performance on which that proposed determination is based.

[93] Elsewhere in the preamble we refer to the potential for efficiency improvements to lead to increased competitiveness and therefore increased utilization as a ''rebound effect.''

[94] For simplicity, throughout this preamble we generally refer to the energy output produced by EGUs as electricity, recognizing that some EGUs produce a portion of their energy output in other forms, such as steam for heating or process uses. The discussion here applies to both EGUs that produce only electricity and EGUs that produce a combination of electricity and other energy output.

[95] The EPA assessed opportunities to achieve CO_2 reductions through heat rate improvements at both coal-fired steam EGUs and non-coal-fired fossil fuel-fired EGUs, such as oil/gas-fired steam EGUs and NGCC units. At this time we are proposing that the basis for supporting the BSER should include heat rate improvements only at coal-fired steam EGUs, but we are inviting comment on including heat rate improvements at other EGU types. See Section VI.C.5 for further discussion of our assessment of heat rate opportunities for non-coal-fired EGUs.

[96] These estimated ranges are averages applicable to the fleet of coal-fired steam EGUs as a whole. Potential improvements at individual EGUs could be higher or lower.

[97] As noted above, in the absence of other kinds of CO_2 emission reduction measures, the emission reductions achievable through heat rate improvements could be offset to some extent by increased utilization of EGUs making the improvements (a ''rebound effect''). See Section VI.C.1 below for further discussion.

combined cycle (IGCC) units. We also found that for these new units the costs were not unreasonable, either for individual units or on a national basis, and we proposed to find that application of partial CCS is the BSER. However, application of CCS at existing units would entail additional considerations beyond those at issue for new units. Specifically, the cost of integrating a retrofit CCS system into an existing facility would be expected to be substantial, and some existing EGUs might have space limitations and thus might not be able to accommodate the expansion needed to install CCS. Further, the aggregated costs of applying CCS as a component of the BSER for the large number of existing fossil fuel-fired steam EGUs would be substantial and would be expected to affect the cost and potentially the supply of electricity on a national basis. For these reasons, although some individual facilities may find implementation of CCS to be a viable CO_2 mitigation option in their particular circumstances,[98] the EPA is not proposing and does not expect to finalize CCS as a component of the BSER for existing EGUs in this rulemaking.[99] Nevertheless, CCS would be available to states and sources as a compliance option.

Natural gas co-firing or conversion at coal-fired steam EGUs offers greater potential CO_2 emission reductions than heat rate improvements, but at a higher cost (although less than the cost of applying CCS technology). Because natural gas contains less carbon than an energy-equivalent quantity of coal, converting a coal-fired steam EGU to burn only natural gas would reduce the unit's CO_2 emissions by approximately 40 percent. The CO_2 reductions are generally proportional to the amount of gas substituted for coal, so if an EGU continued to burn mostly coal while co-firing natural gas as, for example, 10 percent of the EGU's total heat input, the CO_2 emission reductions would be approximately four percent. The EPA determined that the most significant cost associated with natural gas conversion or co-firing is likely to be the incremental cost of natural gas relative to the cost of coal. Using Energy Information Administration (EIA) fuel price projections, we estimated that the CO_2 reductions achieved through natural gas conversion or co-firing at an average coal-fired steam EGU would have costs ranging from approximately $83 to $150 per metric ton.[100] Thus, although there have been past instances where coal-fired steam EGUs have been converted to natural gas, and we expect some additional future conversions where circumstances at individual EGUs make the option particularly attractive, for the industry as a whole we would expect that other approaches could reduce CO_2 emissions from existing EGUs at lower cost. However, gas conversion or co-firing would be available to states and sources as a compliance option, and, as noted later in the preamble, we are seeking comment on whether this option should be considered part of the BSER.

3. CO_2 Emission Reductions Achievable Through Re-Dispatch From Steam EGUs to NGCC Units

The second grouping of CO_2 emission reduction options evaluated by the EPA in the BSER analysis involves reducing emissions by shifting generation among affected EGUs. An obvious alternative to substituting natural gas for coal at individual steam EGUs through conversion or co-firing is instead to use natural gas to generate electricity at a different affected EGU with a better heat rate—notably a natural gas combined cycle (NGCC) unit—and to substitute that electricity for electricity from the coal-fired steam EGU, thus resulting in lower emissions from the coal-fired steam EGU and lower emissions from the set of affected EGUs overall.[101] The electricity system is physically interconnected or networked and operated on an integrated basis across large regions. System operators routinely increase or decrease the electricity output of individual EGUs to respond to changes in electricity demand, equipment availability, and relative operating costs (or bid prices) of individual EGUs while observing reliability-related constraints. It has long been common industry practice for system operators to choose from among multiple EGUs when deciding which EGU to ''dispatch'' to generate the next increment of electricity needed to meet demand. Thus, the well-established practices of the industry support our evaluation of ''re-dispatch'' of generation from steam EGUs to NGCC units as a potential component of the basis for the BSER to reduce CO_2 emissions from existing EGUs.

NGCC units can produce as much as 46 percent more electricity from a given quantity of natural gas than steam EGUs,[102] making the re-dispatch approach a significantly less expensive way to reduce CO_2 emissions than conversion or co-firing of coal-fired steam EGUs to burn natural gas. For example, using the same EIA fuel cost projections as were used above to estimate the costs of natural gas conversion or co-firing, we estimated that the cost of CO_2 reductions achievable by substituting electricity from an existing NGCC unit for electricity from an average coal-fired steam EGU would be approximately $30 per metric ton.[103]

Our analysis indicated that the potential CO_2 reductions available through re-dispatch from steam EGUs to NGCC units are substantial. As of 2012, there was approximately 245 GW of NGCC capacity in the United States, 196 GW of which was placed in service between 2000 and 2012.[104] In 2012, the average utilization rate of U.S. NGCC capacity was 46 percent, well below the utilization rates the units are capable of achieving. In 2012 approximately 10 percent of NGCC plants operated at annual utilization rates of 70 percent or higher, and 19 percent of NGCC units operated at utilization rates of at least 70 percent over the summer season. Average reported availability generally exceeds 85 percent. We recognize that the ability to increase NGCC utilization rates may also be affected by infrastructure and system considerations, such as limits on the ability of the natural gas industry to produce and deliver the increased quantities of natural gas, the ability of steam EGUs to reduce generation while remaining ready to supply electricity when needed in peak demand hours, and the ability of the electric transmission system to accommodate the changed geographic pattern of generation. However, these considerations have not limited past rapid increases in NGCC generation levels, as indicated by a 20 percent increase in natural gas consumption for

[98] CCS already has been or is being implemented at some existing EGUs, as noted in the discussion of CCS later in the preamble.

[99] As noted later in this preamble, we are nevertheless seeking comment on the extent to which existing EGUs could implement CCS in order to improve our understanding.

[100] The lower end of the range is for conversion to 100 percent natural gas, which would allow EGUs to eliminate certain fixed operating and maintenance costs associated with coal use but not natural gas use. See Section VI.C.5.a below for further discussion.

[101] Strategies in this grouping also include shifting generation from steam EGUs burning oil or natural gas to more efficient NGCC units.

[102] This estimate assumes an average heat rate of 10,434 Btu/kWh for coal fossil fuel-fired steam units between 400 and 600 MW and 7,130 Btu/kWh for NGCC units between 400 and 600 MW. See NEEDSv.5.13 at *http://www.epa.gov/powersectormodeling/BaseCasev513.html.*

[103] See Section VI.C.2 below for further discussion.

[104] EIA Form 860, available at *http://www.eia.gov/electricity/data/eia860.* In comparison, in 2012 there was 336 GW of coal steam capacity, of which 22 GW was placed in service between 2000 and 2012. Id.

electricity generation from 2011 to 2012.[105] Further, we have taken these considerations into account, and the proposal's compliance schedule provides flexibility and time for investment in additional natural gas and electric industry infrastructure if needed.

As discussed below in Section VI.C.2, the data and considerations cited above support our assessment that an average NGCC utilization rate in a range of 65 to 75 percent is a reasonable target for the amount of additional NGCC generation that could be substituted for higher carbon generation from steam EGUs as part of the BSER.[106] If re-dispatch consistent with a target average NGCC utilization rate of 70 percent had been achieved in 2012, the combined CO_2 emissions of steam EGUs and NGCCs would have been reduced by approximately 13 percent.

Finally, we also note that mechanisms for encouraging re-dispatch as a CO_2 reduction measure have already been developed and applied in the industry. Under both RGGI and California's Global Warming Solutions Act, shifting generation from more carbon-intensive EGUs to less carbon-intensive EGUs is a way to facilitate compliance with regulatory requirements. In both cases, the industry has demonstrated the ability to respond to the regulatory requirements of these state programs.

4. CO_2 Emission Reductions Achievable Through Other Actions Underway in the Industry

The third grouping of CO_2 emission reduction options the EPA evaluated in the BSER analysis encompasses other measures already used in the industry and not included in the first two groupings. From our evaluation of re-dispatch as an option for reducing CO_2 emissions, it was apparent that relevant factors for consideration include the integrated nature of the electricity system and the fact that particular measures capable of reducing CO_2 emissions at EGUs were already being used and would continue to be used throughout the industry, either for the purpose of compliance with CO_2 emission reduction requirements or to serve other purposes and policy goals. That observation led us to consider what other potential actions and options the industry was already using that had resulted in or could result in, or support, the reduction of CO_2 emissions at EGUs. Again, we observed many such instances, some taking place incidental to the routine operation of the electricity system and others taking place in response to specific state initiatives to reduce CO_2 emissions from the power sector. We concluded that there are two principal types of such potential options for measures that support CO_2 emission reductions at EGUs affected under this proposal: Ongoing development and use of low- and zero-carbon generating capacity, and ongoing development and application of demand-side energy efficiency measures.

Low-and zero-carbon generating capacity provides electricity that can be substituted for generation from more carbon-intensive EGUs. More than half the states already have established some form of state-level renewable energy requirements, with targets calling on average for almost 20 percent of 2020 generation to be supplied from renewable sources. The EPA is unaware of analogous state policies to support development of new nuclear units, but 30 states already have nuclear EGUs (with five units under construction) and the generation from these units is currently helping to avoid CO_2 emissions from fossil fuel-fired EGUs. Policies that encourage development of renewable energy capacity and discourage premature retirement of nuclear capacity could be useful elements of CO_2 reduction strategies and are consistent with current industry behavior. Costs of CO_2 reductions achievable through these policies have been estimated in a range from $10 to $40 per metric ton.[107]

Demand-side energy efficiency programs produce electricity-dependent services with less electricity, and thereby support reduced generation from existing fossil fuel-fired EGUs by reducing the demand for that generation. Reduced generation results in lower CO_2 emissions. More than 40 states already have established some form of demand-side energy efficiency polices, and individual states have avoided up to 13 percent of their electricity demand. Again, policies that encourage demand-side energy efficiency could be useful elements of CO_2 reduction strategies and are consistent with current industry behavior. Using conservatively high estimates of the costs of demand-side energy efficiency, the EPA estimates that the costs of CO_2 emission reductions achievable consistent with such policies would be in a range of $16 to $24 per metric ton.[108]

5. Summary of Building Blocks for the Best System of Emission Reduction

Based on the analytic approach summarized above, the EPA has identified the following four principal categories—''building blocks''—of measures that provide the foundation of our BSER determination for CO_2 emissions from existing EGUs:

1. Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements.

2. Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including NGCC units under construction).

3. Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.

4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

Since they either result in improved operating efficiency or support reductions in mass emissions at existing EGUs, each of the four building blocks represents a demonstrated basis for reducing CO_2 emissions from affected EGUs that is already being pursued in the power sector. In the next subsection, we discuss each of the building blocks at length. Our approach for applying the building blocks to each state's circumstances in order to develop state goals is described in Section VII of this preamble.

C. Detailed Discussion of Building Blocks and Other Options Considered

In this subsection we discuss each of the building blocks in turn. For each building block, we provide our proposed assessment of the technical potential of the building block and the reasonableness of its costs within the context of the BSER determination, and we describe how we developed the data inputs used in the computations of the proposed state goals described in Section VII.C and the alternate goals offered for comment in Section VII.E. We also discuss certain measures that we are not proposing to consider as part of the best system of emission reduction. Additional detail is provided

[105] EIA Form 923, available at *http://www.eia.gov/electricity/data/eia923/.*

[106] Substitution would only occur to the extent that there is both NGCC capacity whose generation could be increased and steam EGUs whose generation could be decreased.

[107] See Section VI.C.3 below for further discussion.

[108] See Section VI.C.4 below for further discussion.

in the Greenhouse Gas Abatement Measures TSD.

It is worth noting that although the discussion below necessarily addresses the building blocks individually, states are not required to pursue plans involving any given building block or to do so at any particular level of stringency. Rather, states have flexibility to establish plans to meet their state emission limitations using their own preferred combinations of efficacious measures applied to the extent determined appropriate by the states. The EPA expects that states and affected EGUs are unlikely to limit themselves to the measures in any single building block, but instead are likely to pursue portfolios of measures from a combination of the actions encompassed in the building blocks. In developing the data inputs to be used in computing state goals, the EPA has estimated reasonable rather than maximum possible implementation levels for each building block in order to establish overall state goals that are achievable while allowing states to take advantage of the flexibility to pursue some building blocks more extensively, and others less extensively, than is reflected in the goal computations, according to each state's needs and preferences.

1. Building Block 1—Heat Rate Improvements

The first category of approaches to reducing CO_2 emissions at affected fossil fuel-fired EGUs consists of measures that reduce the carbon intensity of generation at individual coal-fired steam EGUs [109] by improving heat rate. Heat rate improvements are changes that increase the efficiency with which an EGU converts fuel energy to electric energy (and useful thermal energy in the case of units that cogenerate steam for process use as well as electricity), thereby reducing the amount of fuel needed to produce the same amount of electricity and lowering the amount of CO_2 produced as a byproduct of fuel combustion. Heat rate improvements yield important benefits to affected sources by reducing their fuel costs.

The EPA is aware of the potential for ''rebound effects'' from improvements in heat rates at individual EGUs. In this context, a rebound effect would occur where, because of an improvement in its heat rate, an EGU experiences a reduction in variable operating costs that makes the EGU more competitive relative to other EGUs and consequently raises the EGU's generation output. The increase in the EGU's CO_2 emissions associated with the increase in generation output would offset the reduction in the EGU's CO_2 emissions caused by the decrease in its heat rate and rate of CO_2 emissions per unit of generation output. The extent of the offset would depend on the extent to which the EGU's generation output increased (as well as the CO_2 emission rates of the EGUs whose generation was displaced). The EPA considers the rebound effect to be a potential concern if heat rate improvements were the only approaches being considered for the BSER, but believes that the effect can be addressed by establishing the BSER as a combination of approaches that includes not only heat rate improvements but also approaches that will encourage reductions in electricity demand or increases in generation from lower- or zero-emitting EGUs. The topic of potential rebound effects is discussed further in Sections VI.D and VI.E below. For purposes of the remainder of this subsection, no rebound effect is assumed.

Although heat rate improvements have the potential to reduce CO_2 emissions from all types of affected EGUs, the EPA's analysis indicates the potential is significantly greater for coal-fired steam EGUs than for other EGUs, and for purposes of determining the best system of emission reduction at this time, the EPA is conservatively proposing to base its estimate of CO_2 emission reductions from heat rate improvements on coal-fired steam EGUs only.[110] The remainder of this subsection focuses on the EPA's analysis of potential heat rate improvements from coal-fired steam EGUs. Our analysis of potential heat rate improvements from other types of affected EGUs is addressed in Section VI.C.5 below.

a. Ability of Heat Rate Improvements To Reduce CO_2 Emissions

The heat rate of an EGU is the amount of fuel energy input needed (Btu, higher heating value basis) to produce 1 kWh of net electrical energy output (and useful thermal energy in the case of cogeneration units).[111] The current weighted-average annual heat rate of U.S. coal-fired EGUs in the range of 400 to 600 MW is approximately 10,434 Btu per net kWh.[112] Because an EGU's CO_2 emissions are driven primarily by the amount of fuel consumed, at any fossil fuel-fired EGU there is a strong correlation between potential heat rate improvements and potential reductions in carbon-intensity.[113]

Several studies have examined the opportunities to employ heat rate improvements as a means of reducing CO_2 emissions from coal-fired power plants.[114] Among these, a 2009 study by the engineering firm Sargent & Lundy used bottom-up engineering approaches evaluating potential heat rate improvements from specific best practices and equipment upgrades, including upgrades to boilers, steam turbines, and control systems. Based on this study, the EPA believes that implementation of all identified best practices and equipment upgrades at a facility could provide total heat rate improvements in a range of approximately 4 to 12 percent. (We recognize that individual EGUs would only be able to implement the best practices or upgrades that were applicable to their specific designs or fuel types and that had not already been implemented.)

In addition to the Sargent & Lundy study, which looked generically at the types of improvements that can be made at specific types of EGUs, historical heat rate data also provides a basis for

[109] A ''steam EGU'' is an EGU that combusts fuel in a boiler and uses the combustion heat to create steam which is then used to drive a steam turbine that drives a generator to create electricity. In contrast, a ''combined cycle EGU'' combusts fuel in a combustion turbine that directly drives a generator, and the waste heat is then used to create steam which is used to drive a steam turbine that drives a generator to create more electricity. Steam EGUs can combust a wide variety of fuels including coal and natural gas. Combined cycle EGUs are more efficient at converting fuel energy to electric energy but are limited to gaseous or liquid fuels, most commonly natural gas or distillate oil. Almost all existing coal-fired EGUs are steam EGUs (the exceptions are integrated gasification combined cycle (IGCC) units where coal is processed to create a gaseous fuel that is then combusted in a combined cycle unit).

[110] As noted in Section VI.C.5.d below, we are taking comment on including heat rate improvement opportunities at other EGU types in the basis for supporting the BSER. Also, for compliance purposes states and EGUs would be able to rely on CO_2 emission reductions achieved through heat rate improvements at other types of EGUs.

[111] Heat rate can also be expressed on a gross basis—i.e., fuel input per kWh of gross electricity generated—instead of a net basis—i.e., fuel input per kWh of net electricity sent to the grid. The difference between gross and net electricity is the amount of electricity used at the plant to operate components such as pumps, fans, motors, and pollution control devices.

[112] See NEEDSv.5.13 at *http://www.epa.gov/powersectormodeling/BaseCasev513.html.*

[113] A small portion of some fossil fuel-fired EGU's CO_2 emissions may come from sources other than fuel, such as limestone or other carbonates used to capture sulfur dioxide (SO_2) and/or hydrogen chloride (HCl) in a scrubber or dry injection system. However, CO_2 emissions from these reagents will also tend to be reduced by heat rate improvements, because reagent usage, and the associated CO_2 emissions, will decrease when the amount of fuel used decreases.

[114] See chapter 2 of the GHG Abatement Measures TSD for details.

discerning the existence and possible magnitude of potential heat rate improvements. Many EGUs regularly report to both the EPA and the U.S. Department of Energy's Energy Information Administration (EIA) CO_2 emissions and generation data, from which heat input and heat rate data can be computed. We have reviewed these data and have identified several ''data apparent'' instances where an EGU's heat rate experienced a substantial improvement in a short time—presumably because of equipment upgrades installed at that point in time—that was then sustained. These heat rate improvements ranged from 3 to 8 percent. In combination with bottom-up engineering analysis and the further, more detailed EPA analysis of hourly data summarized below, the individual EGU heat rate histories provide a strong basis for considering heat rate improvement as a meaningful potential approach to reducing the carbon intensity of generation at individual affected fossil fuel-fired EGUs.

b. Amounts of Heat Rate Improvements

In order to estimate the technical potential of heat rate improvement opportunities at existing fossil fuel-fired EGUs suggested by the discussion above, the EPA pursued two principal areas of analysis. The first area concerned the heat rate improvements that could be achieved by reducing heat rate variability at individual coal-fired EGUs through adoption of best practices for operation and maintenance. The second area concerned heat rate improvement opportunities that could be achieved through further equipment upgrades. Both analyses are summarized below along with our conclusions, and are discussed in greater detail in the GHG Abatement Measures TSD.

For the best practices analysis, the EPA worked with the hourly data reported to the EPA by affected EGUs subject to the monitoring and reporting requirements of 40 CFR Part 75. The reported data include hourly heat input and, for most reporting EGUs, hourly gross generation, making it possible to compute hourly gross heat rates. We used the hourly data to assess variability in the hourly gross heat rates of approximately 900 individual coal-fired steam EGUs over the period from 2002 to 2012. Specifically, the EPA evaluated the consistency with which individual EGUs maintained their hourly heat rates over time. We expected that a certain degree of short-term heat rate variability was caused by factors beyond operators' control, notably variation in hourly ambient temperature and hourly load, and preliminary analysis confirmed our expectation. We therefore controlled for variation in those factors by grouping the observed hourly heat rate data for each EGU into subsets corresponding to ranges of hourly ambient temperatures and hourly load levels.[115] We believe that the amount of residual variability within each data subset is an indication of the degree of technical potential to improve the consistency with which optimal heat rate performance is achieved by adopting operating and maintenance best practices. For example, optimal heat rate performance could be achieved with greater consistency through practices such as turning off unneeded pumps at reduced loads, installation of digital control systems, more frequent tuning of existing control systems, or earlier like-kind replacement of worn existing components. (Upgrades to existing equipment are considered below.) By applying best practices to their operating and maintenance procedures, owners and operators of EGUs could reduce heat rate variability relative to average heat rates and, because the deviations generally result in performance worse than the optimal heat rates, improve the EGUs' average heat rates. Assuming that between 10 percent and 50 percent of the deviation from top decile performance in each subset of hourly heat rate observations within defined ranges of temperature and load could be eliminated through adoption of best practices, the result is a corresponding estimated range of 1.3 percent to 6.7 percent technical potential for improvement in the average heat rate of the entire fleet of coal-fired EGUs.[116] Based on this analysis, we believe a reasonable estimate for purposes of developing state-specific goals is that affected coal-fired steam EGUs on average could achieve a four percent improvement in heat rate through adoption of best practices to reduce hourly heat rate variability. This estimate corresponds to the elimination, on average across the fleet of affected EGUs, of 30 percent of the deviation from top-decile performance in the hourly heat rate for each EGU not attributable to hourly temperature and load variation. We also solicit comment on the use of estimates up to six percent, reflecting elimination on average of 50 percent of the deviation from top-decile performance.

For the equipment upgrade analysis, we evaluated potential opportunities to improve heat rates at affected EGUs through specific upgrades identified in the 2009 Sargent & Lundy study. In that study, Sargent & Lundy estimated ranges of potential heat rate improvement achievable through a variety of equipment upgrades. We screened the upgrades from the study to identify what we consider to be a reasonable subset of equipment upgrades that would generally be beyond the scope of investments we would expect to be made for purposes of achieving the best-practices heat rate improvements discussed above. Based on the average of the study's ranges of potential heat rate improvements from the various upgrades in this subset, implementation of the full subset of appropriate opportunities at a single EGU could be expected to result in an aggregate heat rate improvement of approximately four percent (incremental to the improvement achievable from adoption of best practices). However, we recognize that this total may overstate the average equipment upgrade opportunity across all EGUs because some EGUs may have already implemented some of these upgrades. We therefore propose to use as a data input for purposes of developing state goals an estimate that, on average across the fleet of affected EGUs, only half of the full equipment upgrade opportunity just described remains—i.e., that for the fleet of affected EGUs as a whole, the technical potential for heat rate improvements from equipment upgrades incremental to the best-practices opportunity is on average two percent rather than four percent. We solicit comment on increasing this figure up to four percent.

Some of the measures available to EGUs for reducing their carbon intensity affect net heat rates rather than gross heat rates. Various EGU components such as pumps, fans, motors, and pollution control devices use electricity, a factor that is not accounted for in gross heat rates (that is, fuel used per unit of gross energy output) but is accounted for in net heat rates (that is, fuel used per unit of net energy output sent to the electric grid or used for thermal purposes). The electricity used by these components, referred to as auxiliary or parasitic load, may represent from 4 to 12 percent of gross generation at a coal-fired steam EGU.[117] The analysis of

[115] Temperature data are from the National Oceanic and Atmospheric Administration's Integrated Surface Data, *http://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/integrated-surface-database-isd*. Electrical generation data are from the EPA's Air Markets Program Data, *http://ampd.epa.gov/ampd/*.

[116] We examined whether the potential for heat rate improvement varied based on EGU characteristics such as capacity, boiler type, and location, and found no meaningful differences.

[117] Electric Power Research Institute 2011 Technical Report—Program on Technology Innovation: Electricity Use in the Electric Sector

technical potential to reduce heat rate variability discussed above was based on gross heat rate data. Like gross heat rate, parasitic load can be addressed both through adoption of best practices and through equipment upgrades, and some measures undertaken at EGUs may affect parasitic load as well as gross heat rate. Because the hourly generation data reported to the EPA represent gross generation, we have less data available to directly analyze potential net heat rate improvements than gross heat rate improvements. We have therefore not included any separate estimate of parasitic load reductions achievable through best practices in our goal-setting data inputs. However, these opportunities would be available as a mechanism for reducing carbon-intensity at affected EGUs and thus provide more flexibility and opportunities for sources to improve their heat rates at reasonable costs.[118]

The total of the estimated potential heat rate improvements from adoption of best practices to reduce heat rate variability and implementation of equipment upgrades as discussed above is six percent. This total is used as the data input for heat rate improvements in the computation of proposed state goals discussed in Section VII.C below. Because of the close relationship between an EGU's fuel consumption and its CO_2 emissions, a six percent heat rate improvement would be associated with a reduction in CO_2 emissions of approximately six percent. We believe that this represents a reasonable estimate of the technical potential for CO_2 emission reductions that would be achievable from affected coal-fired steam EGUs, on average, through heat rate improvements as an element of the best system of emission reduction.

For purposes of developing the alternate set of goals on which we are taking comment, as described in Section VII.E below, we have used a more conservative estimate of a four percent heat rate improvement from affected coal-fired EGUs on average. This level of improvement would be consistent with those EGUs on average implementing best practices to reduce heat rate variability without making further equipment upgrades, or would be consistent with those EGUs on average implementing both best practices and equipment upgrades, but to a lesser degree than we have projected as being achievable for purposes of our proposal. We view the four percent estimate as a reasonable minimum estimate of the technical potential for heat rate improvement on average across affected coal-fired steam EGUs.

c. Costs of Heat Rate Improvements

By definition, any heat rate improvement made for the purpose of reducing CO_2 emissions will also reduce the amount of fuel the EGU consumes to produce its electricity output. The cost attributable to CO_2 emission reductions therefore would be the net cost to achieve the heat rate improvement after any savings from reduced fuel expense. As summarized below, we estimate that, on average, the savings in fuel cost associated with a six percent heat rate improvement would be sufficient to cover much of the associated costs, with the result that the net costs of heat rate improvements associated with reducing CO_2 emissions from affected EGUs are relatively low.

The EPA's most detailed estimates of the average costs required to achieve the full range of heat rate improvements come from the 2009 Sargent & Lundy study discussed above. Based on the study, the EPA estimated that for a range of heat rate improvements from 415 to 1205 Btus per kWh, corresponding to percentage heat rate improvements of 4 to 12 percent for a typical coal-fired EGU, the required capital costs would range from $40 to $150 per kW. To correspond to the average heat rate improvement of six percent that we have estimated to be achievable through the combination of best practices and equipment upgrades, we have estimated an average cost of $100 per kW, slightly above the midpoint of the Sargent & Lundy study's range. At an estimated annual capital charge rate of 14.3 percent, the carrying cost of an estimated $100 per kW investment would be $14.30 per kW-year. For a coal-fired EGU with a heat rate of 10,450 Btu per kWh, a utilization rate of 78 percent, and a coal price of $2.62 per MMBtu, a six percent heat rate improvement would produce fuel cost savings of approximately $11.20 per kW-year,[119] leaving approximately $3.10 per kW-year of carrying cost not recovered through fuel cost savings. At an average CO_2 emission rate of 0.976 metric tons per MWh, the same six percent heat rate improvement would reduce CO_2 emissions by 0.40 metric tons per kW-year.[120] Thus, the average cost of CO_2 reductions from heat rate improvements would be approximately $7.75 per metric ton of CO_2 ($3.10/0.40). If the average heat rate improvement achievable for the $100 per kW investment were only four percent, consistent with the heat rate improvement estimate in the alternate goals on which we seek comment, the average cost of CO_2 reductions would be $11.63 per metric ton.[121] On the other hand, if an average heat rate improvement of four percent could be achieved for an average investment of $50 per kW, reflecting an assumption that the first improvements pursued would be the least expensive ones, the average cost of CO_2 reductions would fall to $5.81 per metric ton.[122]

The EPA recognizes that the simplified cost analysis just described will represent the costs for some EGUs better than others because of differences in EGUs' individual circumstances. We further recognize that reductions in the utilization rates of coal-fired EGUs anticipated from other components proposed for inclusion in the best system of emission reduction would tend to reduce the fuel savings associated with heat rate improvements, thereby raising the effective cost of achieving the CO_2 emission reductions from the heat rate improvements. Nevertheless, we still expect that the majority of the investment required to capture the technical potential for CO_2 emission reductions from heat rate improvements would be offset by fuel savings, and that the net costs of heat rate improvements as an approach to reducing CO_2 emissions from existing fossil fuel-fired EGUs are reasonable.

Based on the analyses of technical potential and cost summarized above, we propose to find that a six percent reduction in the CO_2 emission rate of the coal-fired EGUs in a state, on average, is a reasonable estimate of the amount of heat rate improvement that can be implemented at a reasonable cost.[123]

(Opportunities to Enhance Electric Energy Efficiency in the Production and Delivery of Electricity).

[118] As proposed, the state-specific goals are expressed in the form of CO_2 emissions per net MWh, and reporting requirements for sources would be in the same form, allowing parasitic load reductions to contribute to improved measured heat rates. If goals and reporting requirements were changed to a gross MWh basis in the final rule, accounting for parasitic load reductions as a source of CO_2 reductions would require additional procedures.

[119] 10,450 Btu/kWh * 8760 hours/year * 78% utilization * $2.62 per MMBtu * 6% improvement * 0.000001 MMBtu/Btu = $11.2 per kW-year. Data inputs for average coal-fired EGU heat rate, average coal-fired EGU utilization, and average coal price are from the IPM 5.13 base case for 2020.

[120] 8760 hours/year * 78% utilization * 0.976 metric tons/Mwh * 6% improvement * 0.001 MW/kW = 0.40 metric tons of CO_2 per kW-year. The estimated average coal-fired EGU CO_2 emission rate per MWh is from the IPM 5.13 base case for 2020.

[121] $7.75 per metric ton of CO_2 * 6%/4% = $11.63 per metric ton of CO_2.

[122] $11.63 per metric ton of CO_2 * $50/$100 = $5.81 per metric ton of CO_2.

[123] We note that although we expect that heat rate improvements are also available from other fossil

Continued

We invite comment on all aspects of our analyses and findings related to heat rate improvements, both as summarized here and as further discussed in the Greenhouse Gas Abatement Measures TSD. As noted earlier, we specifically request comment on increasing the estimates of the amounts of heat rate improvement achievable through adoption of best practices for operation and maintenance and through equipment upgrades up to six percent and four percent, respectively, representing a total potential improvement of up to ten percent, particularly in light of the reasonable cost of heat rate improvements. We also solicit comment on the quantitative impacts on the net heat rates of coal-fired steam EGUs of operation at loads less than the rated maximum unit loads.

2. Building Block 2—Dispatch Changes Among Affected EGUs

The second element of the foundation for the EPA's BSER determination for reducing CO_2 emissions at affected fossil fuel-fired EGUs goes to the achievement of reductions in mass emissions at certain affected EGUs—in particular, fossil fuel-fired steam EGUs—and entails an analysis of the extent to which generation at the most carbon-intensive affected EGUs—again, in particular, fossil fuel-fired steam EGUs—can be replaced with generation at less carbon-intensive affected fossil fuel-fired EGUs—in particular, NGCC units that were in operation or had commenced construction as of January 8, 2014, and are therefore affected units for purposes of this rule.

a. Ability of Re-Dispatch To Reduce CO_2 Emissions

The nation's EGUs are interconnected by transmission grids extending over large regions. EGU owners and grid operators, subject to various reliability and operational constraints, use the flexibility provided by these interconnections to prioritize among available EGUs when deciding which units should be called upon (i.e., ''dispatched'') to increase or decrease generation in order to meet electricity demand at any point in time. Recognizing that increments of generation are to some extent interchangeable, dispatch decisions are based on electricity demand at a given point in time, the variable costs of available generating resources, and system constraints. This system of security-constrained economic dispatch assures reliable and affordable electricity. Electricity demand varies across geography and time in response to numerous conditions, such that EGU owners and grid operators are constantly responding to changes in demand and ''re-dispatching'' to meet demand in the most reliable and cost-effective manner possible. Since the enactment and implementation of Title IV of the CAA Amendments of 1990, in regions where EGUs are subject to market-based programs to limit emissions of pollutants such as SO_2 and NO_X, the costs of emission allowances have been factored directly into those EGUs' variable costs, like the variable costs of operating pollution control devices, and have thereby been accounted for in least-cost economic dispatch decisions by grid operators. Similarly, operators of EGUs subject to CO_2 emissions limits in RGGI now include the cost of RGGI CO_2 allowances in those EGUs' variable costs,[124] creating economic incentives to replace generation at higher-emitting EGUs with generation from lower-emitting sources to reduce CO_2 emissions at the former through the process of least-cost economic dispatch. As an alternate mechanism, permitting authorities can impose limits on utilization or CO_2 emissions at higher-emitting EGUs, in which case grid operators and other market participants would use the integrated electricity system to find other ways to meet the demand for electricity services, either through demand-side energy efficiency or through increased generation from lower-emitting EGUs. In either case, whether implemented through economic mechanisms or permit limitations, reducing emissions at high carbon-intensity EGUs is technically feasible and can reduce overall power sector CO_2 emissions because generation at such EGUs can be replaced by generation at less carbon-intensive EGUs.

We have also analyzed potential upstream net methane emissions impact from natural gas and coal for the impacts analysis. This analysis indicated that any net impacts from methane emissions are likely to be small compared to the CO_2 emissions reduction impacts of shifting power generation from coal-fired steam EGUs to NGCC units. Further information on our analysis of upstream impacts can be found in Appendix 3A of the RIA.

b. Magnitude of Re-Dispatch

Having identified replacing generation at higher-emitting EGUs with generation at lower-emitting EGUs as a technically feasible CO_2 emissions reduction strategy, we next address the quantity of replacement generation that may be relied upon at reasonable costs. The U.S. electric generating fleet includes EGUs employing a variety of generating technologies. EGUs using technologies with relatively low variable costs, such as nuclear units, are for economic reasons generally operated at their maximum output whenever they are available. Renewable EGUs such as wind and solar units also have low variable costs, but in any event are generally operated when wind and sun conditions permit rather than at operators' discretion. In contrast, fossil fuel-fired EGUs have higher variable costs and are also relatively flexible. Fossil fuel-fired EGUs are therefore generally the units that operators use to respond to intra-day and intra-week changes in demand. Because of these typical characteristics of the various EGU types, the primary re-dispatch opportunities among existing units available to EGU owners and grid operators generally consist of opportunities to shift generation among various fossil fuel-fired units, in particular between coal-fired EGUs (as well as oil- and gas-fired steam EGUs) and NGCC units. In the shortterm—that is, over time intervals shorter than the time required to build a new EGU—fossil fuel-fired units consequently tend to compete more with one another than with nuclear and renewable EGUs. The amount of re-dispatch from coal-fired EGUs to NGCC units that takes place as a result of this competition is highly relevant to overall power sector GHG emissions, because a typical NGCC unit produces less than half as much CO_2 per MWh of electricity generated as a typical coal-fired EGU.

In order to estimate the potential magnitude of the opportunity to reduce power sector CO_2 emissions through re-dispatch among existing EGUs, the EPA first examined information on the design capabilities and availability of NGCC units. This examination showed that, although most NGCC units have historically been operated in intermediate-duty roles for economic reasons, they are technically capable of

fuel-fired EGUs, we have conservatively not included CO_2 emission rate reductions for those EGUs in the state goals. However, as discussed in Section VI.C.5.d below, we are requesting comment on this aspect of the proposal. Further, states and sources would be free to use heat rate improvements at those other units to help reach the state goals.

[124] The PJM market monitor publishes breakdowns of wholesale energy prices, including a CO_2 emission allowance cost component, based on analysis of the prices bid by the ''marginal'' EGUs. See Monitoring Analytics, 2013 State of the Market Report for PJM at 103–05, tbls. 3–63 & 3–64 (2014), available at *http://www.monitoringanalytics.com/reports/pjm_state_of_the_market/2013.shtml.*

operating in base-load roles at much higher annual utilization rates. Average annual availability (that is, the percentage of annual hours when an EGU is not in a forced or maintenance outage) for NGCC units in the U.S. generally exceeds 85 percent, and can exceed 90 percent for some groups.[125]

We also researched historical data to determine the utilization rates that NGCC units have already been demonstrated capable of sustaining. Over the last several years, EGU owners and grid operators have engaged in considerable re-dispatch among various types of fossil fuel-fired units relative to historical dispatch patterns, with NGCC units increasing generation and many coal-fired EGUs reducing generation. In fact, in April 2012, for the first time ever the total quantity of electricity generated nationwide from natural gas was approximately equal to the total quantity of electricity generated nationwide from coal.[126] These changes in generation patterns have been driven largely by changes over time in the relative prices of natural gas and coal, in addition to lower overall demand for electricity. Although the relative fuel prices vary by location, as do the recent patterns of re-dispatch, this trend holds across broad regions of the U.S. In the aggregate, the historical data provide ample evidence indicating that, on average, existing NGCC units can achieve and sustain utilization rates higher than their present utilization rates.

The experience of relatively heavily used NGCC units provides an additional indication of the degree of increase in average NGCC unit utilization that is technically feasible. According to the historical NGCC unit utilization rate data reported to the EPA, in 2012 roughly 10 percent of existing NGCC units operated at annual utilization rates of 70 percent or higher.[127] In effect, these units were being dispatched to provide base-load power. In addition to the 10 percent of NGCC units that operated at a 70 percent utilization rate on an annual basis, some NGCC units operated at high utilization rates for shorter, but still sustained, periods of time in response to high cyclical demand. For example, on a seasonal basis, a significant number of NGCC units have achieved utilization rates between 50 and 80 percent; over the 2012 winter season (December 2011–February 2012) and summer season (June–August 2012), about 16 percent and 19 percent of NGCC units, respectively, operated at utilization rates of 70 percent or more across these entire seasons.[128] During the spring and fall periods when electricity demand levels are typically lower, these units were sometimes idled or operated at much lower capacity factors. Nonetheless, the data clearly demonstrate that a substantial number of existing NGCC units have proven the ability to sustain 70 percent utilization rates for extended periods of time. We view this as strong evidence that increasing the utilization rates of existing NGCC units to 70 percent, not in every individual instance but on average, as part of a comprehensive approach to reducing CO_2 emissions from existing high carbon-intensity EGUs, would be technically feasible.

For purposes of establishing state goals, historical (2012) electric generation data are used to apply each building block and develop each state's goal (expressed as an adjusted CO_2 emission rate in lbs per MWh).[129] In 2012, total electric generation from existing NGCC units was 959 TWh.[130] After the application of NGCC re-dispatch toward a 70 percent target utilization rate, the total generation from these existing sources is projected to be 1,390 TWh per year. Adding in the NGCC units that had commenced construction before January 8, 2014 (and are therefore existing sources for purposes of this proposal) but were not yet in operation in 2012 increases the projected total generation from the full set of existing NGCC units to 1,443 TWh per year.

Although producing over 1,400 TWh of generation in 2020 from existing NGCC units is not actually required, because states may choose other abatement measures to reach the state goals, the EPA nevertheless believes that producing this quantity of generation from this set of NGCC units is feasible. As a reference point, NGCC generation increased by approximately 430 TWh (an 80 percent increase) between 2005 and 2012. The EPA calculates that NGCC generation in 2020 could increase by approximately 50 percent from today's levels. This reflects a smaller ramp-up rate in NGCC generation than has been observed from 2005 to 2012. We also expect an increase in NGCC generation of this amount would not impair power system reliability. As we note in the TSD on Resource Adequacy and Reliability, the level of potential re-dispatch can be accommodated within the flexible compliance requirements of the rule. Similar conclusions have been reached in recent studies of the potential impact of emission reductions from existing power plants.[131]

The EPA also examined the technical capability of the natural gas supply and delivery system to provide increased quantities of natural gas and the capability of the electricity transmission system to accommodate shifting generation patterns. For several reasons, we conclude that these systems would be capable of supporting the degree of increased NGCC utilization needed for states to achieve the proposed goals. First, the natural gas pipeline system is already supporting national average NGCC utilization rates of 60 percent or higher during peak hours, which are the hours when constraints on pipelines or electricity transmission networks are most likely to arise. NGCC unit utilization rates during the range of peak daytime hours from 10 a.m. to 9 p.m. are typically 15 to 20 percentage points above their average utilization rates (which have recently been in the range of 40 to 50 percent).[132] Fleet-wide combined-cycle average monthly utilization rates have reached 65 percent,[133] showing that the pipeline system can currently support these rates for an extended period. If the current pipeline and transmission systems allow these utilization rates to be achieved in peak hours and for extended periods, it is reasonable to expect that similar utilization rates should also be possible in other hours when constraints are typically less severe, and be reliably sustained for other months of the year. The second consideration supporting our view that natural gas and electricity system

[125] See, e.g., North American Electric Reliability Corp., 2008–2012 Generating Unit Statistical Brochure—All Units Reporting, *http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx*; Higher Availability of Gas Turbine Combined Cycle, Power Engineering (Feb. 1, 2011), *http://www.power-eng.com/articles/print/volume-115/issue-2/features/higher-availability-of-gas-turbine-combined-cycle.html*.

[126] Today in Energy, EIA (June 6, 2012) (*http://www.eia.gov/todayinenergy/detail.cfm?id=6990*).

[127] The corresponding percentages of NGCC units that in 2012 operated at annual utilization rates of at least 65 percent and at least 75 percent were 16 percent and 6 percent, respectively.

[128] Air Markets Program Data (at *http://ampd.epa.gov/ampd/*).

[129] See Section VII for further explanation of how goals were computed.

[130] For covered sources.

[131] See Greenhouse Gas Emission Reductions From Existing Power Plants: Options to Ensure Electric System Reliability (Analysis Group, Inc., May 2014). Also see the Resource Adequacy Technical Support Document.

[132] EIA, Average utilization of the nation's natural gas combined-cycle power plant fleet is rising, Today in Energy, July 9,2011, *http://www.eia.gov/todayinenergy/detail.cfm?id=1730#*; EIA, Today in Energy, Jan. 15, 2014, *http://www.eia.gov/todayinenergy/detail.cfm?id=14611* (for recent data).

[133] EIA, Electric Power Monthly, February, 2014. Table 6.7.A.

infrastructure would be capable of supporting increased NGCC unit utilization rates is the flexibility of the emission guidelines. The state goals do not require any particular NGCC unit utilization rate to be achieved in any hour or year of the initial plan period. Thus, even if isolated natural gas or electricity system constraints were to limit NGCC unit utilization rates in certain locations in certain hours, this would not prevent an increase in NGCC generation overall across a state or broader region and across all hours. The third consideration supporting a conclusion regarding the adequacy of the infrastructure is that pipeline and transmission planners have repeatedly demonstrated the ability to methodically relieve bottlenecks and expand capacity.[134] Natural gas pipeline capacity has regularly been added in response to increased gas demand and supply, such as the addition of large amounts of new NGCC capacity from 2001 to 2003, or the delivery to market of unconventional gas supplies since 2008. These pipeline capacity increases have added significant deliverability to the natural gas pipeline network to meet the potential demands from increased use of existing NGCC units. Over a longer time period, much more significant pipeline expansion is possible. In previous studies, when the pipeline system was expected to face very large demands for natural gas use by electric utilities about ten years ago, increases of up to 30 percent in total deliverability out of the pipeline system were judged to be possible by the pipeline industry.[135] There have been notable pipeline capacity expansions over the past five years, and substantial additional pipeline expansions are currently under construction.[136] Similarly, the electric transmission system is undergoing substantial expansion.[137] Further, as discussed below in Sections VII.D and VIII of this preamble (on state flexibilities and state plans, respectively), we believe the flexible nature of the proposed goals provides time for infrastructure improvements to occur should they prove necessary in some locations.[138] Combining these factors of currently observed average monthly NGCC utilization rates of up to 65 percent, the flexibility of the emission guidelines, and the availability of time to address any existing infrastructure limitations, it is reasonable to conclude that the natural gas pipeline system can reliably deliver sufficient natural gas supplies, and the electric transmission system can reliably accommodate changed generation patterns, to allow NGCC utilization to increase up to an average annual utilization rate of 70 percent.

We recognize that re-dispatch does contemplate an associated increase in natural gas production, consistent with the current trends in the natural gas industry. The EPA expects the growth in NGCC generation assumed in goal-setting to be feasible and consistent with domestic natural supplies. Increases in the natural gas resource base have led to fundamental changes in the outlook for natural gas. There is general agreement that recoverable natural gas resources will be substantially higher for the foreseeable future than previously anticipated, exerting downward pressure on natural gas prices. According to EIA, proven natural gas reserves have doubled between 2000 and 2012. Domestic production has increased by 32 percent over that same timeframe (from 19.2 TCF in 2000 to 25.3 TCF in 2012). EIA's Annual Energy Outlook for 2014 projects that production will further increase to 29.1 TCF, as a result of increased supplies and favorable market conditions. For comparison, NGCC generation growth of 450 TWh (calculated in goal setting) would result in increased gas consumption of roughly 3.5 TCF for the electricity sector, which is less than the projected increase in natural gas production.

The EPA notes that the assessments described above regarding the ability of the electricity and natural gas industries to achieve the levels of performance indicated for building block 2 in the state goal computations are supported by analysis that has been conducted using the Integrated Planning Model (IPM). IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector that the EPA has used for over two decades to evaluate the economic and emission impacts of prospective environmental policies. To fulfill its purpose of producing projections related to the electric power sector and its related markets—including least-cost capacity expansion and electricity dispatch projections—that reflect industry conditions in as realistic a manner as possible, IPM incorporates representations of constraints related to fuel supply, transmission, and unit dispatch. The model includes a detailed representation of the natural gas pipeline network and the capability to project economic expansion of the network based on pipeline load factors. At the EGU level, IPM includes detailed representations of key operational limitations such as turn-down constraints, which are designed to account for the cycling capabilities of EGUs to ensure that the model properly reflects the distinct operating characteristics of peaking, cycling, and base load units.

As described in more detail below, the EPA used IPM to assess the costs of requiring increasing levels of re-dispatch from higher- to lower-emitting EGUs, and to that end, the EPA developed a series of modeling scenarios that explored shifting generation from existing coal-fired EGUs to existing NGCC units on a 1:1 basis within defined areas.[139] By the nature of IPM's design, those scenarios necessarily also require compliance with the constraints just described (as implemented for any specific scenario). IPM was able to arrive at a solution for scenarios reflecting average NGCC utilization rates of 65, 70, and 75 percent, while observing the market, technical, and regulatory constraints embedded in the model. Such a result is consistent with the EPA's determination that increasing the utilization rates of existing NGCC units to 70 percent, not in every individual instance but on average, as part of a comprehensive approach to reducing CO_2 emissions from existing high carbon-intensity EGUs, would be technically feasible.

c. Cost of Re-Dispatch

Having established the technical feasibility and quantification of replacing incremental generation at

[134] See, e.g., EIA, Natural Gas Pipeline Additions in 2011, Today in Energy; INGAA Foundation, Pipeline and Storage Infrastructure Requirements for a 30 Tcf Market (2004 update); INGAA Foundation, North American Midstream Infrastructure Through 2035—A Secure Energy Future Report (2011).

[135] Pipeline and Storage Infrastructure Requirements for a 30 Tcf Market, INGAA Foundation, 1999 (Updated July, 2004); U.S. gas groups confident of 30-tcf market, Oil and Gas Journal, 1999.

[136] For example, between 2010 and April 2014, 118 pipeline projects with 44,107 MMcf/day of capacity (4,699 miles of pipe) were placed in service, and between April 2014 and 2016 an additional 47 pipeline projects with 20,505 MMcf/day of capacity (1,567 miles of pipe) are scheduled for completion. Energy Information Administration, *http://www.eia.gov/naturalgas/data.cfm*.

[137] According to the Edison Electric Institute, member companies are planning over 170 projects through 2024, with costs totaling approximately $60.6 billion (this is only a portion of the total transmission investment anticipated). Approximately 75 percent of the reported projects (over 13,000 line miles) are high voltage (345 kV and higher). *http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf*.

[138] See Section VII.D and Section VIII below for discussion of timing flexibility.

[139] See Chapter 3 of the Regulatory Impact Analysis for more detail.

higher-emitting EGUs with generation at NGCC facilities as a CO_2 emissions reduction strategy, we next turn to the question of cost. The cost of the power sector CO_2 emission reductions that can be achieved through re-dispatch among existing fossil fuel-fired EGUs depends on the relative variable costs of electricity production at EGUs with different degrees of carbon intensity. These variable costs are driven by the EGUs' respective fuel costs and by the efficiencies with which they can convert fuel to electricity (i.e., their heat rates). Historically, natural gas has had a higher cost per unit of energy content (e.g., MMBtu) than coal in most locations, but for NGCC units this disadvantage in fuel cost per MMBtu relative to coal-fired EGUs is typically offset in significant part, and sometimes completely, by a heat rate advantage.

The EPA has conducted two sets of extensive analyses to help inform the development of the state-specific emission goals described in this proposal, including analyses of the opportunity to reduce CO_2 emissions through re-dispatch. The first set was a dispatch-only set that provided a framework for understanding the broader economic and emissions implications of shifting generation to NGCC units from more carbon-intensive EGUs without consideration of emission reduction measures reflected in the other building blocks. The second set included additional refinements and more closely reflected all the characteristics of the proposed goals that were used as the basis for assessing the costs and benefits of the overall proposal.[140] Both sets of analyses were conducted using IPM.

The first set—the dispatch-only analyses—explored the magnitude and cost of potential opportunities to shift generation from existing coal-fired EGUs to existing NGCC units within defined areas. The purpose of analyzing these scenarios was to understand and demonstrate to what extent existing NGCC units could increase their dispatch at reasonable costs and without significant impacts on other economic variables such as the prices of natural gas and electricity. To evaluate how EGU owners and grid operators could respond to a state plan's possible requirements, signals, or incentives to re-dispatch from more carbon-intensive to less carbon-intensive EGUs, the EPA analyzed a series of scenarios in which the fleet of NGCC units nationwide was required, on average, to achieve a specified annual utilization rate.[141] Specifically, the scenarios required average NGCC unit utilization rates of at least 65, 70, and 75 percent, respectively. For each scenario, we identified the set of dispatch decisions that would meet electricity demand at the lowest total cost, subject to all other specified operating and reliability constraints for the scenario, including the specified average NGCC unit utilization rate. Further, we allowed re-dispatch to occur exclusively within a region's existing fleet.[142]

The costs and economic impacts of the various scenarios were evaluated by comparing the total costs and emissions from each scenario to the costs and emissions from a business-as-usual scenario. For the scenario reflecting a 70 percent NGCC utilization rate, comparison to the business-as-usual case indicates that the average cost of the CO_2 reductions achieved over the 2020–2029 period was $30 per metric ton of CO_2.[143] We view these estimated costs as reasonable and therefore as supporting the use of a 70 percent utilization rate target for purposes of quantifying the emission reductions achievable at a reasonable cost through the application of the BSER.

However, we also note that the costs just described are higher than we would expect to actually occur in real-world compliance with this proposal's goals. One reason for this is that the 70 percent utilization rate in the scenario exaggerates the stringency with which building block 2 is actually reflected in each of the state goals: While the goal computation procedure uses 70 percent as a target NGCC utilization rate for all states, for only 29 states do the goals actually reflect reaching that target NGCC utilization, with the result that the average NGCC utilization rate reflected in the computed state goals is only 64 percent.[144] Also, at least some states may be able to achieve additional emission reductions through other components of the BSER, and those other components may be relatively inexpensive. The dispatch-only analyses were focused on evaluating the potential impacts of re-dispatch in particular, and as a result, they reflect an assumption that even in a state where re-dispatch might be relatively expensive compared to other available CO_2 emission reduction measures that are part of the BSER, the state plan would rely on re-dispatch to the same extent as the plans of other states. In practice, under these circumstances, states would have flexibility to choose among alternative CO_2 reduction strategies that were part of the BSER, instead of relying on re-dispatch to the maximum extent.

The EPA also analyzed dispatch-only scenarios where shifting of generation among EGUs was limited by state boundaries. In these scenarios with less re-dispatch flexibility, the cost of achieving the quantity of CO_2 reductions corresponding to a nationwide average NGCC unit utilization of 70 percent was $33 per metric ton. Combining the results of the modeling with the factors likely to be present in the real world reinforces the support we expressed above for the 70 percent utilization rate. We remain concerned, however, that higher NGCC utilization rates could be harder to sustain and could exert further upward pressure on prices.

We invite comment on whether the regional or state scenarios should be given greater weight in establishing the appropriate degree of re-dispatch to incorporate into the state goals for CO_2 emission reductions, and in assessing costs.

We also conclude from our analyses that the extent of re-dispatch estimated in this building block can be achieved without causing significant economic impacts. For example, in both of the 70 percent NGCC unit utilization rate scenarios—with re-dispatch limited to regional and state boundaries, respectively—delivered natural gas prices were projected to increase by an average of no more than ten percent over the 2020–2029 period, which is well within the range of historical natural gas price variability.[145] Projected wholesale electricity price increases over the same period were less than seven percent in both cases, which similarly is well within the range of historical electric price variability.[146]

[140] See Regulatory Impact Analysis for more detail.

[141] The utilization rate constraint applied on average to all NGCC units nationwide and did not apply to individual NGCC units or to the fleets of NGCC units within individual states.

[142] To best reflect the integrated nature of the electric power sector, the EPA defined six regions for this analysis, the borders of which are informed by North American Electric Reliability (NERC) regions and Regional Transmission Organizations (RTOs). See Chapter 3 of the Regulatory Impact Analysis for more detail.

[143] The analogous costs for the scenarios with 65 and 75 percent NGCC utilization rates were $21 and $40 per metric ton of CO_2, respectively. For further detail on cost methodology, data inputs, and results, refer to Chapter 3 of the GHG Abatement Measures TSD.

[144] For further explanation of the state goal computation methodology, see Section VII of the preamble and the Goal Computation TSD.

[145] According to EIA data, year-to-year changes in natural gas prices at Henry Hub averaged 29.9 percent over the period from 2000 to 2013. *http://www.eia.gov/dnav/ng/hist/rngwhhdA.htm.*

[146] For example, year-on-year changes in PJM wholesale electricity prices averaged 19.5 percent

Continued

We view these projected impacts as not unreasonable and as supporting use of a 70 percent NGCC utilization rate target for purposes of quantifying the emission reductions achievable through application of the BSER.

However, for the same reasons discussed above with respect to estimated costs per ton of CO_2, in actual implementation we again expect that the economic impacts shown in these scenarios, including natural gas price impacts, are likely overstated compared to the impacts that would actually occur in real-world compliance with this rule's proposed goals. Consistent with this expectation, the comprehensive analyses used to assess the compliance costs and benefits of this proposal, which reflect a more complete representation of the additional flexibility available to states, show significantly smaller economic impacts. These analyses are discussed in Section X below.

Based on the analyses summarized above, the EPA proposes that for purposes of establishing state goals, a reasonable estimate regarding the degree of mass emission reductions achievable at fossil fuel-fired steam EGUs can be determined based on the degree to which electricity generation could be shifted from more carbon-intensive EGUs to less carbon-intensive EGUs within the state at reasonable cost through re-dispatch. The increment of emission reductions incorporated in this component of our proposed BSER determination is commensurate with an annual utilization rate for the state's NGCC units of up to 70 percent, on average across all the NGCC units in the state.

For purposes of the alternative set of goals on which we are seeking comment, we have used the less stringent target of a 65 percent average utilization rate for NGCC units. In 2012, approximately 16 percent of existing NGCC plants larger than 25 megawatts had utilization rates equal to or higher than this level. Also, as noted earlier, average NGCC utilization nationwide is already over 60 percent in some peak hours. We therefore view 65 percent as a reasonable lower-bound estimate of an achievable average NGCC utilization rate, and we would expect the costs and economic impacts from re-dispatch associated with a 65 percent NGCC utilization target to be lower than the costs and impacts associated with the 70 percent utilization target. Our cost analysis indicated that CO_2 emission reductions consistent with a 65 percent average NGCC utilization rate could be achieved at a cost of $21 per metric ton.

As discussed above, in addition to analyzing the impacts of using the proposed 70 percent target utilization rate for existing NGCC units, the EPA has also performed preliminary analysis of the impacts of using a target utilization rate for existing NGCC units of 75 percent. That analysis showed that CO_2 emission reductions consistent with a 75 percent target utilization rate could be achieved at a cost of $40 per metric ton.[147] We invite comment on whether we should consider options for a target utilization rate for existing NGCC units greater than the proposed 70 percent target utilization rate.

We invite comment on these proposed findings and on all other issues raised by the discussion above and the related portions of the Greenhouse Gas Abatement Measures TSD.

3. Building Block 3—Using an Expanded Amount of Less Carbon-Intensive Generating Capacity

The third element of the foundation for the EPA's BSER determination for reducing CO_2 emissions at affected fossil fuel-fired EGUs also goes to the achievement of reductions in mass emissions, but in this case the reductions would occur at all affected EGUs, and entails an analysis of the extent to which generation at the affected EGUs can be replaced by using an expanded amount of lower-carbon generating capacity to produce replacement generation. Below we discuss two types of generating capacity that can play this role: Renewable generating capacity and new and preserved nuclear capacity.

a. Renewable Generating Capacity

Renewable electricity (RE) generating technologies are a well-established part of the U.S. power sector. In 2012, electricity generated from renewable technologies, including conventional hydropower, represented 12 percent of total U.S. electricity generation, up from 9 percent in 2005. More than half the states have established renewable portfolio standards (RPS) that require minimum proportions of electricity sales to be supplied with generation from renewable generating resources.[148] Production of this renewable generation replaces predominantly fossil fuel-fired generation and thereby avoids the CO_2 emissions from that replaced generation. The EPA believes that renewable electricity generation is a proven way to assure reductions of CO_2 emissions at affected EGUs at a reasonable cost.[149]

1. Proposed Quantification of Renewable Energy Generation

To estimate the CO_2 emission reductions from affected EGUs achievable based on increases in renewable generation, the EPA has developed a ''best practices'' scenario for renewable energy generation based on the RPS requirements already established by a majority of states. The EPA views the existing RPS requirements as a reasonable foundation upon which to develop such a scenario for two principal reasons. First, in establishing the requirements, states have already had the opportunity to assess those requirements against a range of policy objectives including both feasibility and costs. These prior state assessments therefore support the feasibility and cost of the best practices scenario as well. Second, renewable resource development potential varies by region, and the RPS requirements developed by the states necessarily reflect consideration of the states' own respective regional contexts.[150]

The EPA has not assumed any specific type of renewable generating technology for the best practices scenario. Also, the scenario is not an EPA forecast of renewable capacity development and neither establishes RPS requirements that any state must meet nor makes any determinations regarding allowable RE compliance measures. Rather, it represents a level of renewable resource development for individual states—with recognition of regional differences—that we view as reasonable and consistent with policies that a majority of states have already adopted based on their own policy objectives and assessments of feasibility and cost.

As noted above, renewable resource potential varies regionally. This geographic pattern is reflected in the existing RPS requirements of the various states. Recognizing this pattern, the EPA has grouped the states into six regions for purposes of developing the best

over the period from 2000 to 2013. Ventyx Velocity Suite, ISO real-time data for all hours. Price variability for other eastern ISO regions (NYISO, ISO–NE., and Midcontinent ISO) was similar. Id.

[147] For further analysis related to the use of a 75 percent target utilization rate for NGCC units, see chapter 3 of the GHG Abatement Measures TSD.

[148] Database of State Incentives for Renewables & Efficiency (DSIRE), *http://www.dsireusa.org/summarymaps/index.cfm?ee=0&RE=0.*

[149] For discussion of how states and sources might use RE in state plans, see Section VIII below.

[150] The EPA recognizes that individual RPS policies vary in their specification of where qualifying RE generation must occur. However, the EPA believes the regional structure of this estimation exercise supports a broad interpretation of RPS requirements across states within a region as a proxy for reasonable-cost RE generation potential within the same region.

practices scenario.[151] By comparing each state to a set of neighbors rather than to a single national standard, we are able to take regional variation into account while still maintaining a level of rigor for the scenario's targets. The regional structure is informed by North American Electric Reliability Corporation (NERC) regions and Regional Transmission Organizations (RTOs), with adjustments to align regional borders with state borders and to group Florida and Texas with neighboring states.[152] This structure accounts for similar power system characteristics as well as geographic similarities in RE potential. The grouping of states into the six regions is shown in Table 5 below.

TABLE 5—REGIONS FOR DEVELOPMENT OF BEST PRACTICES RPS SCENARIO

Region	States
East Central	Delaware, District of Columbia*, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia.
North Central	Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, North Dakota, South Dakota, Wisconsin.
Northeast	Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, Vermont*.
South Central	Arkansas, Kansas, Louisiana, Nebraska, Oklahoma, Texas.
Southeast	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee.
West	Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming.

* Because Vermont and the District of Columbia lack affected sources, no goals are being proposed for these jurisdictions.

The best practices scenario for each state consists of increasing annual levels of RE generation estimated based on application of an annual RE growth factor to the state's historical RE generation, subject to a maximum RE generation target. The annual RE growth factors and maximum RE generation targets were developed separately for each of the six regions. Our procedure for determining these elements is described in the Greenhouse Gas Abatement Measures TSD and summarized below.

The EPA first quantified the amount of renewable generation in 2012 in each state. The EPA then summed these amounts for all states in each region to determine a regional starting level of renewable generation prior to implementation of the best practices scenario. Hydropower generation is excluded from this existing 2012 generation for purposes of quantifying BSER-related RE generation potential because building the methodology from a baseline that includes large amounts of existing hydropower generation could distort regional targets that are later applied to states lacking that existing hydropower capacity. The exclusion of pre-existing hydropower generation from the baseline of this target-setting framework does not prevent states from considering incremental hydropower generation from existing facilities (or later-built facilities) as an option for compliance with state goals.

Next, the EPA estimated the aggregate target level of RE generation in each of the six regions assuming that all states within each region can achieve the RE performance represented by an average of RPS requirements in states within that region that have adopted such requirements. For this purpose, the EPA averaged the existing RPS percentage requirements that will be applicable in 2020 and multiplied that average percentage by the total 2012 generation for the region. We also computed each state's maximum RE generation target in the best practices scenario as its own 2012 generation multiplied by that average percentage. (For some states that already have RPS requirements in place, these amounts are less than their RPS targets for 2030.)

For each region we then computed the regional growth factor necessary to increase regional RE generation from the regional starting level to the regional target through investment in new RE capacity, assuming that the new investment begins in 2017, the year following the initial state plan submission deadline,[153] and continues through 2029. This regional growth factor is the growth factor used for each state in that region to develop the best practices scenario.

Finally, we developed the annual RE generation levels for each state. To do this, we applied the appropriate regional growth factor to that state's initial RE generation level, starting in 2017, but stopping at the point when additional growth would cause total RE generation for the state to exceed the state's maximum RE generation target. For computation of the proposed state goals discussed in Section VII.C below, we used the annual amounts for the years 2020 through 2029. For computation of the alternate state goals discussed in Section VII.E below, on which we are seeking comment, we used the annual amounts for the years 2020 through 2024.

Alaska and Hawaii are treated as separate regions. Their RE targets are based on the lowest regional RE target among the continental U.S. regions and their growth factors are based upon historical growth rates in their own RE generation. We invite comment regarding the treatment of Alaska and Hawaii as part of this method.

For details on the regional targets and growth factors applied, please refer to Chapter 4 of the GHG Abatement Measures TSD.

The cumulative RE amounts for each state, represented as percentages of total generation, are shown in Table 6.

[151] Given their unique locations, Alaska and Hawaii are not grouped with other states into these regions. As a conservative approach to estimating RE generation potential in Alaska and Hawaii, the EPA has developed RE generation targets for each of those states based on the lowest values for the six regions evaluated here.

[152] The regions are the same as those used in regional modeling of this rule; see the Regulatory Impact Analysis for more information on the regional modeling.

[153] See Section VIII below for further discussion of timing requirements for state plan submittals.

TABLE 6—STATE RE GENERATION LEVELS FOR STATE GOAL DEVELOPMENT

[Percentage of annual generation][154]

State	2012 percent)	Proposed goals		Alternate goals	
		Interim level * (percent)	Final level (percent)	Interim level * (percent)	Final level (percent)
Alabama	2	6	9	4	5
Alaska	1	2	2	1	1
Arizona	2	3	4	3	3
Arkansas	3	5	7	4	5
California	15	20	21	20	21
Colorado	12	19	21	17	19
Connecticut	2	5	9	4	5
Delaware	2	7	12	4	5
Florida	2	6	10	4	6
Georgia	3	8	10	6	7
Hawaii	9	10	10	10	10
Idaho	16	21	21	21	21
Illinois	4	7	9	6	7
Indiana	3	5	7	4	5
Iowa	25	15	15	15	15
Kansas	12	19	20	19	20
Kentucky	0	1	2	1	1
Louisiana	2	5	7	4	4
Maine	28	25	25	25	25
Maryland	2	10	16	6	8
Massachusetts	5	15	24	11	13
Michigan	3	6	7	5	6
Minnesota	18	15	15	15	15
Mississippi	3	8	10	6	8
Missouri	1	2	3	2	2
Montana	5	8	10	6	7
Nebraska	4	8	11	6	7
Nevada	8	14	18	12	14
New Hampshire	7	19	25	15	19
New Jersey	2	8	16	5	7
New Mexico	11	18	21	16	18
New York	4	11	18	8	10
North Carolina	2	7	10	5	6
North Dakota	15	15	15	15	15
Ohio	1	6	11	4	5
Oklahoma	11	19	20	18	20
Oregon	12	19	21	17	19
Pennsylvania	2	9	16	5	7
Rhode Island	1	4	6	3	3
South Carolina	2	7	10	5	6
South Dakota	24	15	15	15	15
Tennessee	1	3	6	2	3
Texas	8	16	20	13	15
Utah	3	5	7	4	5
Virginia	3	12	16	9	12
Washington	7	12	15	10	11
West Virginia	2	8	14	5	6
Wisconsin	5	8	11	7	8
Wyoming	9	15	19	13	14

The EPA notes that for some states, the RE generation targets developed using the proposed approach are less than those states' reported RE generation amounts for 2012. We invite comment on whether the approach for quantifying the RE generation component of each state's goal should be modified to include a floor based on reported 2012 RE generation in that state.

This approach to quantification of a state's RE generation target does not explicitly account for the amount of fossil fuel-fired generation in that state. Without such an accounting, the application of this approach could yield, for a given state, an increase in RE generation that exceeds the state's reported 2012 fossil fuel-fired generation.[155] The EPA invites comment on whether this approach should be modified so that the difference between a state's RE generation target and its 2012 level of corresponding RE generation does not exceed the state's

[154] Vermont and the District of Columbia are excluded from this table because we are not proposing goals for those jurisdictions.

[155] In this proposed RE approach, this situation only occurs with the RE targets quantified for the state of Washington.

reported 2012 fossil fuel-fired generation.[156]

We note that with the exception of hydropower, the RE generation levels represent total amounts of RE generation, rather than incremental amounts above a particular baseline level. As a result, this RE generation can be supplied by any RE capacity regardless of its date of installation. This approach is therefore focused on quantifying the fulfillment of each state's potential for the deployment of RE as part of BSER using a methodology that does not require discriminating between RE capacity that was installed before or after any given date. Under this approach, states in a given region where a higher proportion of total generation has already been achieved from renewable resources are assumed to have less opportunity for deployment of additional renewable generation as part of the BSER framework informing state goals, in comparison to states in that region where the proportion of total generation achieved from renewable resources to date has been lower. That being said, the assumptions of RE generation used to develop the state goals do not impose any specific RE generation requirements on any state; they are only used to inform the quantification of state goals to which states may respond with whatever emission reduction measures are preferred.

With regard to hydropower, we seek comment regarding whether to include 2012 hydropower generation from each state in that state's ''best practices'' RE quantified under this approach, and whether and how the EPA should consider year-to-year variability in hydropower generation if such generation is included in the RE targets quantified as part of BSER. Chapter 4 of the GHG Abatement Measures TSD presents state RE targets both with and without the inclusion of each state's 2012 hydropower generation.

2. Cost of CO_2 Emission Reductions From RE Generation

The EPA believes that RE generation at the levels represented in the best practices scenario can be achieved at reasonable costs. According to an EPA analysis based on EIA levelized costs, the cost to reduce emissions through RE ranges from $10 to $40 per metric ton of CO_2.[157] Analysis of RE development in response to state RPS policies also finds historical and projected costs of RPS-driven RE deployment to be modest. One comparative analysis that ''synthesize[d] and analyze[d] the results and methodologies of 28 distinct state or utility-level RPS cost impact analyses'' projected the median change in retail electricity price to be $0.0004 per kilowatt-hour (a 0.7 percent increase), the median monthly bill impact to be between $0.13 and $0.82, and the median CO_2 reduction cost to be $3 per metric ton.[158] This finding has been confirmed with more recent RPS cost data, including a report that determined 2010–2012 retail electricity price impacts due to state RPS policies to be less than two percent, with only two states experiencing price impacts of greater than three percent.[159] Additionally, the National Renewable Energy Laboratory has projected low incremental costs for a range of scenarios reflecting significant increases in RE penetration, including scenarios that increase RE penetration to a range of 30 to 40 percent of national generation, levels higher than those projected in our best practices scenario.[160]

While RPS requirements will continue to grow over time, the EPA does not expect this anticipated expansion to fall outside the historical norms of deployment or to create unusual pressure for cost increases. Full compliance with current RPS goals through 2035 would require approximately 4 to 4.5 GW of new renewable capacity per year. Average deployment of RPS-supported renewable capacity from 2007 to 2012 exceeded 6 GW per year.[161] In addition, recent improvements in RPS compliance rates indicate to the EPA the reasonableness of current RPS growth trajectories. Weighted average compliance rates among all states have improved in each of the past three reported years (2008–2011) from 92.1 percent to 95.2 percent despite a 40 percent increase in RPS obligations during this period.[162]

We invite comment on this approach to treatment of renewable generating capacity as a basis for the best system of emission reduction adequately demonstrated and for quantification of state goals.

3. Alternative Approach to Quantification of RE Generation

Additionally, the EPA is soliciting comment on an alternative approach to quantification of renewable generation to support the BSER. Unlike the proposed RE scenario described above that relies on a regional application of state RPS commitments, the alternative methodology relies on a state-by-state assessment of RE technical and market potential. The alternative approach is based on two sources of information: A metric representing the degree to which the technical potential of states to develop RE generation has already been realized, and IPM modeling of RE deployment at the state level under a scenario that reflects a reduced cost of building new renewable generating capacity.

The metric measuring realization of RE technical potential in a state compares each state's existing renewable generation by technology type with the technical potential for that technology in that state as assessed by the National Renewable Energy Laboratory (NREL).[163] This comparison yields, for each state and for each RE technology, a proportion of renewable generation technical potential that has been achieved and can be represented as an RE development rate. For example, if

[156] For example, for the state of Washington the proposed approach yields a final RE generation target of 17.7 TWh, representing an increase of 9.5 TWh over Washington's reported 2012 RE generation (excluding hydropower) of 8.2 TWh. By comparison, Washington's 2012 reported fossil fuel-fired generation was 9.4 TWh. (The 2012 reported RE and fossil fuel-fired generation amounts for all states are included in the Goal Computation TSD.) If the limitation described in the text were applied to Washington, the state's incremental quantified RE generation would be limited to 9.4 TWh, with the result that the state's final RE generation target would be 17.6 TWh instead of 17.7 TWh.

[157] This analysis is based upon EIA's AEO 2014 Estimated Levelized Costs of Electricity for New Generation Sources, available at *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.*

[158] Chen et al., ''Weighing the Costs and Benefits of State Renewable Portfolio Standards: A Comparative Analysis of State-Level Policy Impact Projections,'' Lawrence Berkeley National Laboratory, March 2007, available at *http://emp.lbl.gov/publications/weighing-costs-and-benefits-state-renewables-portfolio-standards-comparative-analysis-s.*

[159] Galen Barbose, ''Renewables Portfolio Standards in the United States: A Status Update,'' Lawrence Berkeley National Lab, November 2013. Also to be published in Heeter et al., ''Estimating the Costs and Benefits of Complying with Renewable Portfolio Standards: Reviewing Experience to Date'' [review draft title]. UNPUBLISHED. National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory.

[160] NREL, ''Renewable Electricity Futures Study'', NREL/TP–6A20–52409, 2012, *http://www.nrel.gov/analysis/re_futures/.*

[161] Galen Barbose, ''Renewables Portfolio Standards in the United States: A Status Update,'' Lawrence Berkeley National Laboratory, November 2013.

[162] *http://emp.lbl.gov/rps*, retrieved March 2014. The RPS compliance measure cited is inclusive of credit multipliers and banked RECs utilized for compliance, but excludes alternative compliance payments, borrowed RECs, deferred obligations, and excess compliance. This estimate does not represent official compliance statistics, which vary in methodology by state.

[163] Lopez *et al.,* NREL, ''U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis,'' (July 2012).

a given state has 500 MWh of solar generation in 2012 while NREL assesses that state's solar generation technical potential at 5,000 MWh/year, then that state's solar RE development rate would be ten percent. The EPA then considers the range of RE development rates across states in order to define a benchmark RE development rate for each technology.

While a benchmark RE development rate offers a useful metric to quantify the proportion of RE generation that would bring all states up to a designated proportion of RE generation that has been achieved in practice by certain states to date, such a metric does not explicitly take into account the cost that would be faced to reach the benchmark RE development rate in each state. In order to take this cost into account, for this alternative approach the EPA has paired the benchmark RE development rates described above with IPM modeling of RE deployment at the state level, based on a scenario reflecting a reduced cost of building new renewable generating capacity. The cost reduction for new RE generating capacity is intended to represent the avoided cost of other actions that could be taken instead to reduce CO_2 emissions from the power sector. In the Alternative RE Approach TSD, available in the docket, we show the RE deployment levels modeled using a cost reduction of up to $30 per MWh, a level that is consistent with the cost range of $10 to $40 per metric ton of avoided CO_2 emissions estimated for the proposed RE scenario described above.[164]

Under this alternative RE approach, the EPA would quantify RE generation for each technology in each state as the lesser of (1) that technology's benchmark rate multiplied by the technology's in-state technical potential, or (2) the IPM-modeled market potential for that specific technology. For example, if the benchmark RE development rate for solar generation is determined to be 12 percent, and the hypothetical state described above has a solar generation technical potential of 5,000 MWh/year, then the benchmark RE development level of generation for that state would be 600 MWh/year. If the IPM-modeled market potential for solar generation in that state is 750 MWh/year, then this approach would quantify solar generation for that state as the benchmark RE development level (600 MWh/year) because it is the lesser amount of those two measures.

Having quantified an amount of RE generation from each RE technology in each state, the EPA would then determine for each state a total level of RE generation that equals the sum of the generation quantified for each of the assessed RE technologies in that state. If the EPA were to adopt this alternative approach for quantifying RE in BSER, these total levels of RE generation for each state would be incorporated in state goals in place of the RE generation levels quantified using the proposed approach described above. Further methodological detail and state-level RE targets for this alternative approach are provided in the Alternative RE Approach TSD in the docket.

We invite comment on this alternative approach to quantification of RE generation to support the BSER. We note that the three specific requests for comment made above with respect to the proposed quantification approach—addressing, first, the possibility of a floor based on 2012 RE generation, second, the possibility of a limitation based on 2012 fossil fuel-fired generation and, third, the treatment of hydropower generation—apply to this alternative approach as well.[165]

Finally, the EPA notes that the alternative RE approach described above is one of a number of possible methodologies for using technical and economic renewable energy potential to quantify RE generation for purposes of state goals. The EPA invites comment on other possible techno-economic approaches. For example, a conceptual framework for another techno-economic approach is provided in the Alternative RE Approach TSD.

b. New and Preserved Nuclear Capacity

Nuclear generating capacity facilitates CO_2 emission reductions at fossil fuel-fired EGUs by providing carbon-free generation that can replace generation at those EGUs. Because of their relatively low variable operating costs, nuclear EGUs that are available to operate typically are dispatched before fossil fuel-fired EGUs. Increasing the amount of nuclear capacity relative to the amount that would otherwise be available to operate is therefore a technically viable approach to support reducing CO_2 emissions from affected fossil fuel-fired EGUs.

1. Proposed Quantification of Nuclear Generation

One way to increase the amount of available nuclear capacity is to build new nuclear EGUs. However, in addition to having low variable operating costs, nuclear generating capacity is also relatively expensive to build compared to other types of generating capacity, and little new nuclear capacity has been constructed in the U.S. in recent years; instead, most recent generating capacity additions have consisted of NGCC or renewable capacity. Nevertheless, five nuclear EGUs at three plants are currently under construction: Watts Bar 2 in Tennessee, Vogtle 3–4 in Georgia, and Summer 2–3 in South Carolina. The EPA believes that since the decisions to construct these units were made prior to this proposal, it is reasonable to view the incremental cost associated with the CO_2 emission reductions available from completion of these units as zero for purposes of setting states' CO_2 reduction goals (although the EPA acknowledges that the planning for those units likely included consideration of the possibility of future regulation of CO_2 emissions from EGUs). Completion of these units therefore represents an opportunity to reduce CO_2 emissions from affected fossil fuel-fired EGUs at a very reasonable cost. For this reason, we are proposing that the emission reductions achievable at affected sources based on the generation provided at the identified nuclear units currently under construction should be factored into the state goals for the respective states where these new units are located. However, the EPA also realizes that reflecting completion of these units in the goals has a significant impact on the calculated goals for the states in which these units are located. If one or more of the units were not completed as projected, that could have a significant impact on the state's ability to meet the goal. We therefore take comment on whether it is appropriate to reflect completion of these units in the state goals and on alternative ways of considering these units when setting state goals.

Another way to increase the amount of available nuclear capacity is to preserve existing nuclear EGUs that might otherwise be retired. The EPA is aware of six nuclear EGUs at five plants that have retired or whose retirements have been announced since 2012: San Onofre Units 2–3 in California, Crystal River 3 in Florida, Kewaunee in Wisconsin, Vermont Yankee in Vermont, and Oyster Creek in New Jersey. While each retirement decision

[164] Additional detail regarding this modeling and approach is provided in the Alternative RE Approach TSD.

[165] The Alternative RE Approach TSD presents the quantification of hydropower generation under the alternative approach, as well as the resulting state RE targets both with and without hydropower generation included.

is based on the unique circumstances of that individual unit, the EPA recognizes that a host of factors—increasing fixed operation and maintenance costs, relatively low wholesale electricity prices, and additional capital investment associated with ensuring plant security and emergency preparedness—have altered the outlook for the U.S. nuclear fleet in recent years. Reflecting similar concern for these challenges, EIA in its most recent Annual Energy Outlook has projected an additional 5.7 GW of capacity reductions to the nuclear fleet. EIA describes the projected capacity reductions—which are not tied to the projected retirement of any specific unit—as necessary to recognize the ''continued economic challenges'' faced by the higher-cost nuclear units.[166] Likewise, without making any judgment about the likelihood that any individual EGU will retire, we view this 5.7 GW, which comprises an approximately six percent share of nuclear capacity, as a reasonable proxy for the amount of nuclear capacity at risk of retirement.

2. Cost of CO_2 Emission Reductions From Nuclear Generation

We have determined that, based on available information regarding the cost and performance of the nuclear fleet, preserving the operation of at-risk nuclear capacity would likely be capable of achieving CO_2 reductions from affected EGUs at a reasonable cost. For example, retaining the estimated six percent of nuclear capacity that is at risk for retirement could support avoiding 200 to 300 million metric tons of CO_2 over an initial compliance phase-in period of ten years.[167] According to a recent report, nuclear units may be experiencing up to a $6/MWh shortfall in covering their operating costs with electricity sales.[168] Assuming that such a revenue shortfall is representative of the incentive to retire at-risk nuclear capacity, one can estimate the value of offsetting the revenue loss at these at-risk nuclear units to be approximately $12 to $17 per metric ton of CO_2. The EPA views this cost as reasonable. We therefore propose that the emission reductions supported by retaining in operation six percent of each state's historical nuclear capacity should be factored into the state goals for the respective states.[169]

For purposes of goal computation, generation from under-construction and preserved nuclear capacity is based on an estimated 90 percent average utilization rate for U.S. nuclear units, consistent with long-term average annual utilization rates observed across the nuclear fleet. The methodology for taking this generation into account for purposes of setting state emission rate goals is described below in Section VII on state goals and in the Goal Computation TSD.

We invite comment on all aspects of the approach discussed above. In addition, we specifically request comment on whether we should include in the state goals an estimated amount of additional nuclear capacity whose construction is sufficiently likely to merit evaluation for potential inclusion in the goal-setting computation. If so, how should we do so—for example, according to EGU owners' announcements, the issuance of permits, projections of new construction by the EPA or another government agency, or commercial projections? What specific data sources should we consider for those permits or projections?

4. Building Block 4—Demand-Side Energy Efficiency

The fourth element of the foundation for the EPA's BSER determination for reducing CO_2 emissions at affected fossil fuel-fired EGUs also supports reduced mass emissions at all affected EGUs, and entails an analysis of the extent to which generation reductions at the affected EGUs can be supported by reducing the demand for generation at those EGUs through measures that reduce the overall quantity of generation demanded by end-users.[170]

a. Benefits of Demand-Side Energy Efficiency

Reducing demand for generation at affected EGUs through policies to improve demand-side energy efficiency is a proven basis for reducing CO_2 emissions at those EGUs. Every state has established demand-side energy efficiency policies, and many stakeholders emphasized the success of these policies in reducing electricity consumption by large amounts. For example, data reported to the U.S. Energy Information Administration (EIA) show that in 2012 California and Minnesota avoided 12.5 percent and 13.1 percent of their electricity demand, respectively, through their demand-side efficiency programs.[171] Additionally, multiple studies have found that significant improvements in end-use energy efficiency can be realized at less cost than the savings from avoided power system costs.[172] Increased investment in demand-side energy efficiency is being supported by efforts at the federal, state, and local levels of government as well as corporate efforts. Many stakeholders urged the inclusion of demand-side energy efficiency policies as compliance options under the CAA section 111(d) guidelines.

By reducing electricity consumption, energy efficiency avoids greenhouse gas emissions associated with electricity generation. Because fossil fuel-fired EGUs typically have higher variable costs than other EGUs (such as nuclear and renewable EGUs), their generation is typically the first to be replaced when demand is reduced. Consequently, reductions in the utilization of fossil fuel-fired EGUs can be supported by reducing electricity consumption and, by the same token, reductions in electricity consumption avoid the CO_2 emissions associated with the avoided generation. In this manner, in 2011, state demand-side energy efficiency programs are estimated to have reduced CO_2 emissions by 75 million metric tons.[173] And when integrated into a comprehensive approach for addressing CO_2 emissions, demand-side energy efficiency improvements offer even more potential to improve the carbon profile of the electricity supply system. For example, if incentives exist to shift generation to lower carbon-intensity EGUs, and those EGUs are fully utilized, reducing demand can support further reductions in carbon intensity. This potential effect reinforces the appropriateness of incorporating demand-side efficiency improvements into a comprehensive approach to address power sector CO_2 emissions. In addition, by supporting reductions in fossil fuel usage at EGUs, demand-side

[166] Jeffrey Jones and Michael Leff, EIA, ''Implications of accelerated power plant retirements,'' (April 2014).

[167] Assuming replacement power for at-risk nuclear capacity is sourced from new NGCC capacity at 800 lbs/MWh or the power system at 1127 lbs CO_2/MWh (average 2020 power sector emissions intensity as projected in the EPA's IPM Base Case).

[168] ''Nuclear * * * The Middle Age Dilemma?'' Eggers, et al., Credit Suisse, February 2013.

[169] A state's historical nuclear fleet is defined as all units in commercial operation as of May 2014 with no current plans to retire.

[170] Electricity end-users and electricity end-use referred to throughout this subsection include the residential, commercial and industrial sectors.

[171] Energy Information Administration Form 861, 2012, available at *http://www.eia.gov/electricity/data/eia861/*.

[172] See, e.g., Electric Power Research Institute, U.S. Energy Efficiency Potential Through 2035 (Final Report, April 2014); Wang, Yu and Marilyn A. Brown, Policy Drivers for Improving Electricity End-Use Efficiency in the U.S.: An Economic-Engineering Analysis (Energy Efficiency, 2014).

[173] Innovation, Electricity, Efficiency (an Institute of the Edison Foundation), Summary of Customer-Funded Electric Efficiency Savings, Expenditures, and Budgets (2011–2012) (March 2013), available at *http://www.edisonfoundation.net/iei/ourwork/Pages/issuebriefs.aspx*.

energy efficiency supports not only reduced CO_2 emissions and carbon intensity of the power sector, but also reduced criteria pollutant emissions, cooling water intake and discharge, and solid waste production associated with fossil fuel combustion. By reducing electricity usage significantly, energy efficiency also commonly reduces the bills of electricity customers.

b. ''Best Practices'' for Demand-Side Energy Efficiency

To estimate the potential CO_2 reductions at affected EGUs that could be supported by implementation of demand-side energy efficiency policies as a part of state goals, the EPA developed a ''best practices'' demand-side energy efficiency scenario. This scenario provides an estimate of the potential for sources and states to implement policies that increase investment in demand-side energy efficiency technologies and practices at reasonable costs. It does not represent an EPA forecast of business-as-usual impacts of state energy efficiency policies or an EPA estimate of the full potential of end-use energy efficiency available to the power system, but rather represents a feasible policy scenario showing the reductions in fossil fuel-fired electricity generation resulting from accelerated use of energy efficiency policies in all states consistent with a level of performance that has already been achieved or required by policies (e.g., energy efficiency resource standards) of the leading states. The data and methodology used to develop the best practices scenario are summarized below.

We have not assumed any particular type of demand-side energy efficiency policy. States with leading energy efficiency performance have employed a variety of strategies that are implemented by a range of entities including investor-owned, municipal and cooperative electric utilities as well as state agencies and third-party administrators. These include energy efficiency programs,[174] building energy codes, state appliance standards (for appliances without federal standards), tax credits, and benchmarking requirements for building energy use.[175] Energy efficiency policies are designed to accelerate the deployment of demand-side energy efficiency technologies, practices, and measures by addressing market barriers and market failures that limit their adoption. Some states have adopted energy efficiency resource standards [176] (EERS) to drive investment in energy efficiency programs; some have relied on other strategies; most states are using multiple policy approaches. Based on historical data on energy efficiency program savings and analysis of the requirements of existing state energy efficiency policies, twelve leading states have either achieved—or have established requirements that will lead them to achieve—annual incremental savings rates of at least 1.5 percent of the electricity demand that would otherwise have occurred.[177] The 1.5 percent savings rate is inclusive of, not additional to, existing state energy efficiency requirements. These savings levels are realized exclusively through the adoption and implementation of energy efficiency programs. The energy savings data underpinning these analyses are derived from energy efficiency program reports required by state public utility commissions and other entities with a similar oversight role.[178] These state commissions define and oversee the analysis and reporting requirements for energy efficiency programs as part of their role of overseeing rates for utility customers in their states. One typical requirement is the application of recognized evaluation, measurement, and validation (EM&V) protocols that specify industry-preferred approaches and methodologies for estimating savings from efficiency programs.[179]

While EM&V data reflect documented electricity savings from energy efficiency programs, they typically do not account for potential electricity savings available from additional state-implemented policies for which EM&V protocols are less consistently required or applied, such as building energy codes. Thus, we consider the 1.5 percent annual incremental savings [180] rate to be a reasonable estimate of the energy efficiency policy performance that is already achieved or required by leading states and that can be achieved at reasonable costs by all states given adequate time. If we were to capture the potential for additional policies, such as the adoption and enforcement of state or local building energy codes, to contribute additional reductions in electricity demand beyond those resulting from energy efficiency programs, we could reasonably increase the targeted annual incremental savings rate beyond 1.5 percent.

For states where EE program experience is more limited, reaching a best-practices level of performance requires undertaking a set of activities that takes some time to plan, implement, and evaluate. For the best practices scenario, we have therefore estimated that each state's annual incremental savings rate increases from its 2012 annual saving rate [181] to a rate of 1.5 percent over a period of years starting in 2017. (Thus, the goal for each state differs to reflect the assumption that in a state already close to a 1.5 percent annual incremental savings rate, energy efficiency programs can be expanded to reach that rate sooner than in a state that is further from that rate.) The pace at which states are estimated to increase their savings rate level is 0.2 percent per year. This rate is consistent with past performance and future requirements of leading states.[182] For states already at or above the 1.5 percent

[174] Energy efficiency programs are driven by a variety of state policies including energy efficiency resource standards, requirements to acquire all cost-effective energy efficiency, integrated resource planning requirements, and demand-side management plans and budgets. Funding for energy efficiency programs is provided through a variety of mechanisms as well, including per kilowatt-hour surcharges and proceeds from forward capacity market and emission allowance auctions. The programs are implemented by a range of entities including investor-owned, municipal, and cooperative electric utilities, state agencies, and designated third-party administrators. All end-use sectors (residential, commercial, and industrial) are targeted by energy efficiency programs and numerous strategies are employed, including targeted rebates for high-efficiency appliances; energy audits with recommendations for cost-effective, energy-saving upgrades; and processes to certify energy efficiency service providers.

[175] See the appendix to the State Plan Considerations TSD for descriptions of the full array of demand-side energy efficiency policies currently employed by states.

[176] EERS establish specific, long-term targets for energy savings that utilities or non-utility program administrators must meet through customer energy efficiency programs. EERS, as well as requirements that utilities acquire all cost-effective energy efficiency, have been the most impactful state energy efficiency strategies in recent years.

[177] The historical data used are reported to the Energy Information Administration through Form EIA–861. The analysis and summary of state energy efficiency policies is from the American Council for an Energy-Efficient Economy (ACEEE), State EERS Activity Policy Brief (February 24, 2014). See the Greenhouse Gas Abatement Measures TSD for more information.

[178] E.g., energy efficiency programs operated by municipal and cooperative utilities may report their program results to their Boards of Directors rather than to a state utility commission.

[179] See the EM&V section of the State Plan TSD for more information on EE program evaluation.

[180] This incremental savings rate and all others discussed in this subsection represent net, rather than gross, energy savings. Gross savings are the changes in energy use (MWh) that result directly from program-related actions taken by program participants, regardless of why they participated in a program. Net savings refer to the changes in energy use that are directly attributable to a particular energy efficiency program after accounting for free-ridership, spillover, and other factors.

[181] 2012 is the most recent year for energy efficiency program incremental savings data reported using EIA Form 861.

[182] See the Greenhouse Gas Abatement Measures TSD for more information.

annual incremental savings rate (based on 2012 reported data), we estimate that they would realize a 1.5 percent rate in 2017 and maintain that rate through 2029. For all states we assume the initial savings rate (the lower of their 2012 value or 1.5 percent) is realized in 2017 and increases each year by 0.2 percent until the target rate of 1.5 percent is achieved [183] and is then maintained at that level through 2029. The savings from energy efficiency programs are cumulative, meaning that, in simplified terms, a state in which a sustained program is implemented with a 1.5 percent annual incremental savings rate could expect cumulative annual savings of approximately 1.5 percent after the first year, 3.0 percent after the second year, 4.5 percent after the third year, and so on. Savings from the first year would drop off at the end of the average life of the energy efficiency program portfolio (typically about ten years). Accordingly, we have projected the cumulative annual savings for each state that would be achieved for the period 2020 to 2029 based on the state's reaching and then sustaining the best practices annual incremental savings rate through 2029. These values, for each state and for each year (2020–2029), are used in the procedure for computing the state goals described in Section VII.C below.

As discussed in Section VII.E below, the EPA is also taking comment on a less stringent alternative for setting state goals. Under this alternative, the demand-side energy efficiency requirement uses 1.0 percent (rather than 1.5 percent) annual incremental savings as representative of the best-practices level of performance. In addition, the pace at which incremental savings levels are increased from their historical levels is relaxed slightly to 0.15 percent per year (rather than 0.2 percent). The 1.0 percent rate of savings is a level of performance that has been achieved—or that established state requirements will cause to be achieved—by 20 states.[184] As is done with the more stringent goal-setting approach for energy efficiency, the cumulative percentages for each state are derived and multiplied by the state's 2012 historical electricity sales as reflected in the EIA detailed state data, in this case for the period from 2020 to 2024.

The state-specific cumulative annual electricity saving data inputs for both the proposed approach and the less stringent alternative are discussed in the Greenhouse Gas Abatement Measures TSD and summarized in Table 7.

TABLE 7—DEMAND-SIDE ENERGY EFFICIENCY STATE GOAL DEVELOPMENT: CUMULATIVE ANNUAL ELECTRICITY SAVINGS (PERCENTAGE OF ANNUAL SALES) RESULTING FROM BEST PRACTICES SCENARIO [185]

State	1.5% Savings target scenario		1.0% Savings target scenario	
	2020	2029	2020	2024
Alabama	1.4	9.5	1.1	3.9
Alaska	1.2	9.5	0.9	3.7
Arizona	5.2	11.4	3.5	6.0
Arkansas	1.5	9.7	1.2	4.1
California	5.0	11.6	3.6	6.1
Colorado	3.9	11.0	3.3	5.9
Connecticut	4.7	11.9	3.6	6.3
Delaware	1.1	9.5	0.9	3.6
Florida	2.0	10.0	1.8	4.7
Georgia	1.8	9.8	1.5	4.4
Hawaii	1.3	9.5	1.0	3.8
Idaho	3.8	11.1	3.5	5.9
Illinois	4.4	11.6	3.5	6.2
Indiana	3.2	11.1	2.9	5.7
Iowa	4.7	11.7	3.6	6.0
Kansas	1.2	9.5	0.9	3.7
Kentucky	1.9	10.0	1.6	4.6
Louisiana	1.1	9.3	0.9	3.6
Maine	5.4	12.1	3.6	6.3
Maryland	4.2	11.5	3.5	6.1
Massachusetts	4.4	11.8	3.6	6.2
Michigan	4.6	11.8	3.6	6.2
Minnesota	4.8	11.7	3.6	6.2
Mississippi	1.4	9.6	1.1	3.9
Missouri	1.6	9.9	1.3	4.2
Montana	3.4	10.9	3.0	5.7
Nebraska	2.2	10.4	1.9	4.9
Nevada	3.0	10.7	2.7	5.5
New Hampshire	2.8	11.0	2.6	5.5
New Jersey	1.3	9.6	1.0	3.7
New Mexico	3.1	10.6	2.8	5.5
New York	4.4	11.8	3.5	6.2
North Carolina	2.4	10.3	2.1	5.0
North Dakota	1.4	9.7	1.1	4.0
Ohio	4.2	11.6	3.5	6.1
Oklahoma	1.9	10.0	1.6	4.5
Oregon	4.7	11.4	3.6	6.1
Pennsylvania	4.7	11.7	3.6	6.2

[183] For example, a state with a reported savings rate of 0.5% in 2012 is assumed to realize a 2017 savings rate of 0.5% and their savings rates for 2018, 2019, 2020, 2021 and 2022 are calculated to be 0.7%, 0.9%, 1.1%, 1.3%, and 1.5%, respectively. By this method, all states have reached the 1.5% target rate by 2017 at the earliest and by 2025 at the latest.

[184] See the Greenhouse Gas Abatement Measures TSD for more information.

TABLE 7—DEMAND-SIDE ENERGY EFFICIENCY STATE GOAL DEVELOPMENT: CUMULATIVE ANNUAL ELECTRICITY SAVINGS (PERCENTAGE OF ANNUAL SALES) RESULTING FROM BEST PRACTICES SCENARIO [185]—Continued

State	1.5% Savings target scenario		1.0% Savings target scenario	
	2020	2029	2020	2024
Rhode Island	3.9	11.6	3.4	6.1
South Carolina	2.3	10.2	2.0	4.9
South Dakota	1.6	9.9	1.3	4.2
Tennessee	2.2	10.3	1.9	4.9
Texas	1.8	9.9	1.5	4.4
Utah	3.6	11.0	3.2	5.8
Virginia	1.2	9.3	1.0	3.7
Washington	4.2	11.3	3.5	6.0
West Virginia	1.8	10.1	1.5	4.4
Wisconsin	4.7	11.8	3.6	6.2
Wyoming	1.6	9.7	1.3	4.2

c. Costs of Demand-Side Energy Efficiency

The EPA expects implementation of demand-side energy efficiency policies as reflected in the best practices scenario to be achievable at reasonable costs. The EPA finds support for the reasonableness of the costs of this building block from two perspectives. First, the specific savings levels represented by this building block were developed based upon the experience and success of states in developing and implementing energy efficiency policies that they undertake primarily for the purpose of providing economic benefits to electricity consumers in their state. Secondly, even with notably conservative assumptions about the costs of achieving the levels of electricity savings associated with this building block, the EPA's analysis of the power sector indicates that the costs are reasonable.

The processes by which states develop funding for energy efficiency programs typically require the application of cost-effectiveness tests to ensure that adopted program portfolios lead to lower costs than the use of generation sources that would otherwise be required to meet the associated electricity service demands. Indeed, a major reason for the widespread presence and rapid growth of demand-side energy efficiency programs is the strong evidence of the reasonableness of their costs even before the additional benefit of CO_2 reductions is considered.[186] Independent studies have found that end-users' needs for energy-dependent services (e.g., heating, cooling, lighting, motor output, and information and entertainment services) frequently can be satisfied at lower cost by improving the efficiency of electricity consumption rather than by increasing the supply of electricity.[187] These factors indicate that the cost of CO_2 reductions achieved through implementation of demand-side energy efficiency at the levels reflected in the best practices scenario are likely to be very reasonable, typically resulting in reductions in average electricity bills across all end-use sectors.[188] Because demand-side energy efficiency costs are incurred at the time of investment, while the cost savings (from lower electricity usage) are realized over the life of these investments (typically about 10 years), bill reductions are greater in later years, but provide substantial payback over the investment period.

Another approach to evaluating the reasonableness of the costs associated with this building block is to compare the demand-side energy efficiency costs to the avoided power system costs as represented within the EPA's modeling of the power sector. The costs associated with the best practices scenario were estimated based upon a synthesis of data and analysis of the factors that impact energy efficiency program costs as calculated using an engineering-based, bottom-up approach that is standard for state and utility analysis of these policies. These factors include the average energy efficiency program costs per unit of first-year energy savings ($/MWh), the ratio of program to participant costs, and the lifetimes of energy efficiency measures across the full portfolio of programs. In addition, the EPA has included a cost escalation factor to represent the possibility of increased costs associated with higher levels of incremental energy savings rates and the national scope of the best practices scenario. The EPA has taken a conservative approach to each of these factors, selecting values that are at the higher-cost end of reasonable ranges of estimated values. The combination of these factors is reflected in the value the EPA has derived for the levelized cost per MWh of saved energy. This value includes both the program costs paid by utilities for implementing energy efficiency programs and the amounts that program participants pay for their own energy efficiency improvements beyond the program costs. These costs are levelized across the measure lifetimes of a full portfolio of energy efficiency programs. This analysis provides a levelized cost of saved energy (LCOSE) range of $85/MWh to $90/MWh ($2011) over the 2020 to 2030 period. This range of LCOSE is notably conservative (leading to higher costs) in comparison with most utility and state analysis. For example, a 2014 analysis by the American Council for an Energy-Efficient Economy (ACEEE) surveyed program and participant cost results across seven states and found a comparable LCOSE value of $54/MWh (2011$).[189]

[185] Vermont and the District of Columbia are excluded from this table because we are not proposing goals for those jurisdictions.

[186] Some states do include a valuation of CO_2 benefits as part of their evaluations of cost effectiveness.

[187] E.g., Electric Power Research Institute, U.S. Energy Efficiency Potential Through 2035 (Final Report, April 2014); Northwest Power and Conservation Council, Sixth Northwest Conservation and Electric Power Plan (Feb. 2010), available at *http://www.nwcouncil.org/energy/powerplan/6/plan/*.

[188] As described below and in the Goal Computation TSD, in the case of a state that is a net importer of electricity, the proposed goal computation procedure includes an adjustment to account for the possibility that some of the generation and emissions avoided due to the state's demand-side energy efficiency programs may occur at EGUs in other states. Given the extremely low cost of CO_2 emission reductions achievable through demand-side energy efficiency programs, implementation of such programs is likely to reduce CO_2 emissions at reasonable cost even for a state whose own affected EGUs achieve only part of the CO_2 emission reduction benefit from the state's demand-side energy efficiency efforts.

[189] American Council for an Energy-Efficient Economy (ACEEE), The Best Value for America's Energy Dollar: A National Review of the Cost of

To estimate the reductions in power system costs and CO_2 emissions associated with the best-practices level of demand-side energy efficiency described above, the EPA analyzed a scenario incorporating the resulting reduction in electricity demand and compared the results with the business-as-usual scenario. Both analyses were conducted using the Integrated Planning Model (IPM) described previously. Combining the resulting power system cost reductions with the energy efficiency cost estimates associated with the best practices scenario, the EPA derived net cost impacts for 2020, 2025, and 2030. Dividing these net cost impacts by the associated CO_2 reductions for each year, the EPA found that the average cost of the CO_2 reductions achieved ranged from $16 to $24 per metric ton of CO_2. The EPA views these estimated costs as reasonable. Together with the history of demonstrated successful state implementation of demand-side energy efficiency programs at reasonable costs discussed above, this analysis supports the reasonableness of the level of demand-side energy efficiency represented by the best practices scenario and, by extension, the reasonableness of the emission reductions at affected EGUs that can be achieved consistent with achievement of that level of demand-side energy efficiency.

Further details regarding the data and methodology used to evaluate the potential for demand-side energy efficiency programs to substitute for generation at affected EGUs and thereby facilitate reductions of power sector CO_2 emissions at reasonable costs are provided in the Greenhouse Gas Abatement Measures TSD. We invite comment on all aspects of our data and methodology as discussed above and in the TSD, as well as on the level of reductions we propose to define as best practices suitable for representation consistent with the best system of emission reduction and the level reflected in the less stringent scenario. We also specifically invite comment on several issues: (1) Increasing the annual incremental savings rate to 2.0 percent and the pace of improvement to 0.25 percent per year to reflect an estimate of the additional electricity savings achievable from state policies not reflected in the 1.5 percent rate and the 0.20 percent per year pace of improvement, such as building energy codes and state appliance standards, (2) alternative approaches and/or data sources (i.e., other than EIA Form 861) for determining each state's current level of annual incremental electricity savings, and (3) alternative approaches and/or data sources for evaluating costs associated with implementation of state demand-side energy efficiency policies.

5. Potential Emission Reduction Measures Not Used To Set Proposed Goals

There are four additional potential measures for reducing, or supporting reduced, GHG emissions from EGUs that the EPA does not propose to consider part of the best system of emission reduction adequately demonstrated for existing EGUs at this time and therefore has not used for goal-setting purposes, but that merit discussion here: Fuel switching at individual EGUs, carbon capture and storage (CCS), using expanded amounts of less carbon-intensive new NGCC capacity to provide replacement generation, and heat rate improvements at affected EGUs other than coal-fired steam EGUs.

a. Fuel Switching at Individual Units

One technically feasible approach for reducing CO_2 emissions per MWh of generation from an EGU designed for coal-fired generation is to substitute natural gas for some or all of the coal. Most existing coal-fired steam EGU boilers can be modified to switch to 100 percent gas input or to co-fire gas with coal in any desired proportion. For certain individual EGUs, switching to or co-firing with gas may be an attractive option for reducing CO_2 emissions.

Changing the type of fuel burned at a steam EGU typically requires certain plant modifications (e.g., new burners) and may have some negative impact on the net efficiencies of the boiler and the overall generation process. If the plant lacks existing gas pipeline infrastructure capable of delivering the necessary quantities of natural gas to the boiler, installation of a new pipeline lateral would also be required.

The capital costs of plant modifications required to switch a coal-fired EGU completely to natural gas are roughly $100–300/kW, excluding pipeline costs. For plants that require additional pipeline capacity, the capital cost of constructing new pipeline laterals is approximately $1 million per mile of pipeline built. Offsetting these capital costs, conversion to 100 percent gas input would typically reduce the EGU's fixed operating and maintenance costs by about 33 percent due mainly to certain equipment retirements and a reduction in staffing, while non-fuel variable costs would be reduced by about 25 percent due to reduced maintenance and waste disposal costs. However, in most cases, the most significant cost change associated with switching from coal to gas in a coal-fired boiler is likely to be the difference in fuel cost. Using EIA's projections of future coal and natural gas prices, switching a steam EGU's fuel from coal to gas typically would more than double the EGU's fuel cost per MWh of generation.

The CO_2 reduction potential of natural gas co-firing or conversion is due largely to the different carbon intensities of coal and natural gas and is directly related to the proportion of gas burned. Greater reductions in the CO_2 emission rate are achieved at higher proportions of gas usage. For example, at ten percent gas co-firing, the net emission rate (e.g., pounds of CO_2 per net MWh of generation) of a typical steam EGU previously burning only coal would decrease by approximately four percent. At 100 percent gas burn, the net emission rate of a typical steam EGU previously burning only coal would decrease by approximately 40 percent.

For a typical base-load coal-fired EGU, and reflecting EIA's projected future natural gas and coal prices, the average cost of CO_2 reductions achieved through gas conversion or co-firing ranges from $83 per metric ton to $150 per metric ton. The low end of the range of CO_2 reduction costs represents a 100 percent switch to gas, because in instances where a combination of coal and gas is burned, the EGU would continue to bear the fixed costs associated with equipment needed for coal combustion, raising the cost per ton of CO_2 reduced.

The EPA's economic analysis suggests that there are more cost effective opportunities for coal-fired utility boilers to reduce their CO_2 emissions than through natural gas conversion or co-firing. As a result, the EPA has not proposed at this time to include this option in the BSER and has not incorporated implementation of the option into the proposed state goals. However, the EPA believes that there are a number of factors that warrant further consideration in determining whether the option should be included. First, the EPA is aware that a number of utilities have reworked some of their coal-fired units to allow for some level of natural gas co-firing (and in some cases have converted the units to fire entirely on natural gas). Second, the EPA is aware of several possible reasons beyond reduction of CO_2 emissions that may make natural gas co-firing economically attractive in some circumstances. One example is that natural gas reburn strategies that involve

Utility Energy Efficiency Programs (Report No. U1402, March 2014).

co-firing with 10 to 20 percent natural gas can be an effective control strategy for NO_X emissions and, thus, can offset operational (and in some cases, capital) costs associated with other NO_X controls such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR). A second example suggested by some vendors is that the capability to burn natural gas in a coal-fired boiler can improve economics because it allows the boiler to operate more effectively at lower loads. A third example, applicable to units that run infrequently but may be needed for reliability purposes, is that converting to or co-firing with natural gas may be more economically attractive than either installing non-CO_2 emission controls or taking other measures, such as transmission upgrades, that could become necessary if the unit were retired. Finally, beyond the reasons just described explaining why EGU owners may find natural gas co-firing to be cost-effective, there are also potentially significant health co-benefits associated with burning natural gas instead of coal.

We solicit comment on whether natural gas co-firing or conversion should be part of the BSER. We also request comment regarding whether, and, if so, how, we should consider the co-benefits of natural gas co-firing in making that determination.

b. Carbon Capture and Storage

Another possible approach for reducing CO_2 emissions from existing fossil fuel-fired EGUs is through the application of carbon capture and storage [190] technology (CCS). In the recently proposed standards of performance for new fossil fuel-fired EGUs (79 FR 1430), the EPA proposed to find that the best system of emission reduction for new fossil fuel-fired boilers and IGCC units is partial application of CCS. In that proposal, the EPA found that, for new units, partial CCS has been adequately demonstrated, it is technically feasible, it can be implemented at costs that are not unreasonable, it provides meaningful emission reductions, and its implementation will serve to promote further development and deployment of the technology. The EPA also noted in the proposal that most of the relatively few new boiler and IGCC EGU projects currently under development are already planning to implement CCS, and, as a result, the proposed standard would not have a significant impact on nationwide energy prices.

In contrast, the EPA did not identify full or partial CCS as the BSER for new natural gas-fired stationary combustion turbines, noting technical challenges to implementation of CCS at NGCC units as compared to implementation at new solid fossil fuel-fired sources. The EPA also noted that, because virtually all new fossil fuel-fired power projects are projected to use NGCC technology, requiring full or partial CCS would have a greater impact on the price of electricity than requiring CCS at the few projected coal plants, and the larger number of NGCC projects would make a CCS requirement difficult to implement in the short term.

Partial CCS has been demonstrated at existing EGUs. It has been demonstrated at a pilot-scale at Southern Company's Plant Barry, it is being installed for large-scale demonstration at NRG's W.A. Parish facility, and it is expected soon to be applied at a commercial scale as a retrofit at SaskPower's Boundary Dam plant in Canada. However, the EPA expects that the costs of integrating a retrofit CCS system into an existing facility would be substantial. For example, some existing sources have a limited footprint and may not have the land available to add a CCS system. Moreover, there are a large number of existing fossil-fired EGUs. Accordingly, the overall costs of requiring CCS would be substantial and would affect the nationwide cost and supply of electricity on a national basis.

For the reasons just described, based on the information available at this time, the EPA does not propose to find that CCS is a component of the best system of emission reduction for CO_2 emissions from existing fossil fuel-fired EGUs. The EPA does solicit comment on all aspects of applying CCS to existing fossil fuel-fired EGUs (in either full or partial configurations), but does not expect to finalize CCS as a component of the BSER in this rulemaking. It should be noted, however, that in light of the fact that several existing fossil-fired EGUs are currently being retrofitted with CCS, the implementation of partial CCS may be a viable GHG mitigation option at some facilities, and as a result, emission reductions achieved through use of the technology could be used to help meet the emission performance level required under a state plan.

Additional discussion can be found in the Greenhouse Gas Abatement Measures TSD.

c. New NGCC Capacity

In Section VI.C.2 above, we discussed the opportunity to reduce CO_2 emissions by replacing generation at high carbon-intensity affected EGUs with lower-carbon generation from existing NGCC units.[191] From a technical perspective, the same potential would exist to replace high-emitting generation with generation from additional NGCC capacity that may be built in the future; the analysis above regarding the feasibility of policies to increase utilization rates of existing NGCC units on average to 70 percent applies equally to new NGCC units.[192] We view the opportunity to reduce CO_2 emissions at affected EGUs by means of addition and operation of new NGCC capacity as clearly feasible.

In addition, we note that our compliance modeling for this proposal suggests that the construction and operation of new NGCC capacity will be undertaken as method of responding to the proposal's requirements.

However, compared to the opportunity to reduce CO_2 emissions at affected EGUs by means of re-dispatch to existing NGCC capacity, the parallel opportunity involving new NGCC capacity would be more costly for several reasons. The first reason is the additional cost associated with additional usage of natural gas. As noted in the discussion of building block 2 above, the EPA analyzed costs associated with several different target utilization rates for existing NGCC units and that analysis showed higher costs of CO_2 reductions at higher target NGCC utilization rates.

The second reason that emission reductions from the use of new NGCC capacity would be more costly is that there would be capital investment costs. Some amount of new NGCC capacity (beyond the units that were already under construction as of January 8, 2014 and are ''existing'' units for purposes of this proposal) would likely be built to meet perceived electricity market demand or to replace less economic capacity regardless of this proposal. The costs of achieving CO_2 emission reductions through re-dispatch to these new NGCC units and through re-dispatch to existing NGCC units would be comparable (ignoring consideration

[190] This is also sometimes referred to as ''carbon capture and sequestration.''

[191] For purposes of this proposal, NGCC units that have commenced construction as of January 8, 2014 are ''existing'' units.

[192] Whether and to what extent adding new NGCC capacity is likely to lead to CO_2 reductions depends on what incentives would exist to operate that new capacity in preference to operation of more carbon-intensive existing EGUs. Because the proposed state goals also reflect the opportunity to reduce utilization of high carbon-intensity EGUs by shifting generation to less carbon-intensive EGUs, we believe that in the context of a comprehensive state plan, the necessary incentives would likely exist, in which case adding new NGCC capacity would tend to reduce CO_2 emissions.

of the cost impacts just discussed related to increases in overall gas usage). However, in the case of any new NGCC units that would not have been built if not for this proposal, and that were built in part for the purpose of achieving CO_2 reductions at affected EGUs, some portion of their construction or fixed operating costs would also be attributable to the CO_2 reduction opportunity, increasing to some extent the cost of the CO_2 reductions at affected EGUs achieved through re-dispatch to those new NGCC units.

The third reason relates to the costs of pipeline infrastructure expansion, and in particular the unevenly distributed nature of those costs. While expanded use of existing NGCC capacity to achieve CO_2 emission reductions can be expected to rely largely on existing pipeline infrastructure with incremental capacity expansions, use of new NGCC capacity—if required in all states—could require substantially greater pipeline infrastructure investments to serve some states than others.

Taken together, the EPA believes the cost considerations just described indicate a higher cost for CO_2 reductions achievable from re-dispatch to new NGCC capacity than from other options, at least for states with limited natural gas pipeline infrastructure, and we therefore do not propose to include this option in state goals.

While the EPA is not proposing that new NGCC capacity is part of the basis supporting the BSER, we recognize that there are a number of new NGCC units being proposed and that many modeling efforts suggest that development of new NGCC capacity would likely be used as a CO_2 emission mitigation strategy. Therefore, we invite comment on whether we should consider construction and use of new NGCC capacity as part of the basis supporting the BSER. Further, we take comment on ways to define appropriate state-level goals based on consideration of new NGCC capacity.

d. Assessment of Heat Rate Improvement Opportunities at Oil-Fired Steam EGUs, Gas-Fired Steam EGUs, NGCC Units, and Simple-Cycle Combustion Turbine Units

The EPA assessed opportunities to improve heat rates at affected EGUs other than coal-fired steam units. This assessment, which is documented in a Technical Memorandum included as an appendix to the GHG Abatement Measures TSD, considers the potential extent of heat rate improvements and CO_2 reductions that could be reasonably available from oil-fired steam EGUs, gas-fired steam EGUs, NGCC units, and simple-cycle combustion turbine units. For these non-coal technologies, the total additional potential CO_2 reductions achievable through heat rate improvements appear relatively small compared to the potential CO_2 reductions achievable through heat rate improvements at coal-fired steam EGUs. For this reason, the EPA does not propose to include heat rate improvement opportunities at these other fossil fuel-fired units as an element of the BSER for CO_2 emissions from affected EGUs at this time. However, we are aware that the proportion of total generation provided from EGUs such as oil-fired steam EGUs or gas-fired steam EGUs varies by location, and may be relatively large in geographically isolated areas such as islands. We therefore invite comment on whether heat rate improvements for some of the EGU types discussed above should be identified as a basis for supporting the BSER, with particular reference to U.S. territories.

Finally, the EPA expects that for some individual oil/gas-fired steam EGUs and NGCC units attractive heat rate improvement opportunities will exist. We note that under the proposed flexible approach to state plans described later in this preamble, CO_2 reductions achieved through such opportunities could be used to help meet state goals, regardless of whether these measures are used as a basis to support the BSER.

D. Potential Combinations of the Building Blocks as Components of the Best System of Emission Reduction

This subsection summarizes the EPA's examination of combinations of the building blocks as components of the BSER, comparing the merits of a potential BSER that comprises only building blocks 1 and 2 with the merits of a BSER that comprises all four building blocks—the preferred option in this proposal. (A more detailed discussion of how we evaluated each option against the criteria to be considered for the BSER follows in Section VI.E.) [193]

1. Reasons for Considering Combinations of Building Blocks

As previously described, the building blocks can be summarized as follows:

Building block 1: Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements.

Building block 2: Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including NGCC units under construction).

Building block 3: Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.

Building block 4: Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

The EPA initially considered a BSER comprising only strategies within building block 1. As described earlier in Section VI.B, the EPA concluded that certain strategies within building block 1—specifically heat rate improvements at individual coal-fired steam EGUs—should be a component of the BSER determination, as they are technically feasible and can be implemented at a reasonable cost. However, the EPA further concluded that, while heat rate improvements qualify as a system of emission reduction, they are not in themselves the BSER as there are additional strategies that can be utilized in combination with building block 1 that are technically feasible, can be implemented at reasonable cost, and result in greater emission reductions than would be achieved through building block 1 strategies alone. The EPA is also concerned that if the measures that improve heat rates at coal-fired steam EGUs in building block 1 are implemented in isolation, without additional measures that reduce overall electricity demand or encourage substitution of less carbon-intensive generation for more carbon-intensive generation, the resulting increased efficiency of coal-fired steam units would provide incentives to operate those EGUs more, leading to smaller overall reductions in CO_2 emissions. Further, in listening sessions and other outreach meetings, the EPA learned that states and other sources were already implementing and pursuing strategies in the other building blocks for the purpose, at least in part, of reducing CO_2 emissions.

2. A Combination of Building Blocks 1 and 2 as the Best System of Emission Reduction

We considered a BSER that comprises strategies from building blocks 1 and 2.

[193] For convenience, the discussion in this Section VI.D is based on our proposal to identify the BSER as consisting of the building blocks themselves. The points made in this discussion are also relevant for our alternative proposal to identify the BSER as consisting of building block 1 coupled with reduced utilization of the affected EGUs in specified amounts.

In this system, emission reductions at the most carbon-intensive individual affected EGUs would occur through a combination of heat rate improvements (resulting in a decrease in emission rates) and substitution of generation at less carbon-intensive affected EGUs, notably existing NGCC units. One reason for considering a BSER comprising these two building blocks is that it involves only affected EGUs and generation from affected EGUs.

The EPA believes that the combination of building blocks 1 and 2 would be a ''system of emission reduction'' capable of achieving significant reductions in CO_2 emissions from affected EGUs at a reasonable cost. As discussed in Section VI.C above, each of the two building blocks independently would be capable of achieving meaningful CO_2 emission reductions at reasonable costs. In combination, the need to achieve the level of emission reductions achievable through use of building block 2 can mitigate the concern that building block 1, implemented alone, would make coal-fired EGUs more economically competitive and lead to increased generation that would offset the emission reduction benefits of the carbon-intensity improvements. While combining the building blocks may also raise the cost per ton of emission reductions achieved through heat rate improvements (by reducing the quantity of MWh generated from the EGUs with improved heat rates and therefore also reducing the aggregate emission reductions achieved at those EGUs by the heat rate improvements), the costs of heat rate improvements are low enough that we believe their cost per ton of emission reduction would remain reasonable.

Nevertheless, the EPA is not proposing that a combination of building blocks 1 and 2 is the BSER, because the proposed combination of all four building blocks discussed below—in other words, adding to the measures in building blocks 1 and 2 the measures in building blocks 3 and 4, which we and stakeholders have identified as already in use—is capable of achieving even greater CO_2 emission reductions from affected EGUs at reasonable costs. The state-specific goals that would be computed consistent with a BSER based on the combination of only building blocks 1 and 2 (i.e., goals computed using the goal computation methodology discussed in Section VII below, except for the omission of building blocks 3 and 4) are presented in the Goal Computation TSD available in the docket. Further information on the EPA's evaluation of this combination is available in the ''Analysis of Emission Reductions, Costs, Benefits and Economic Impacts Associated with Building Blocks 1 and 2'' available in the docket. We invite comment on a potential BSER comprising a combination of building blocks 1 and 2.

3. A Combination of all Four Building Blocks as the Best System of Emission Reduction

Our proposal for the BSER is a combination of all four building blocks. As discussed in Section VI.C above, each of the four building blocks is a proven way to support either improvements in emissions rates at affected EGUs or reductions in EGU mass emissions; each is in widespread use and is independently capable of supporting significant CO_2 reductions from affected EGUs, either on an emission rate or mass-emissions basis, at a reasonable cost consistent with ensuring system reliability. As discussed in Section VI.E below, the combination of all four building blocks provides the basis for satisfying the legal criteria to be considered the BSER. Further, as discussed in Section X below, the combination of all four building blocks can achieve greater overall CO_2 emission reductions from affected EGUs, at a lower cost per unit of CO_2 eliminated, than the combination of building blocks 1 and 2.

In the large and highly integrated electricity system, where electricity is fungible and the demand for electricity services can be met in many ways (including through demand-side energy efficiency), states and the industry have long pursued a wide variety of strategies for ensuring that the demand for electricity services is met reliably, at reasonable costs, and in a manner consistent with evolving constraints, including environmental objectives. These strategies have long extended to the measures in all four building blocks. We believe the combination of all four building blocks fairly represents the range of measures that states and the industry will consider when developing state plans and strategies for reducing CO_2 emissions from affected EGUs while continuing to meet demand for electricity services reliably and affordably. Therefore, we believe it is appropriate to consider that same combination as the BSER upon which the required CO_2 standards of performance for affected EGUs should be based.

E. Determination of the Best System of Emission Reduction

1. Overview

In this section, the EPA explains the ''best system of emission reduction . . . adequately demonstrated.'' This explanation includes what the EPA proposes to determine as the BSER and why. In addition the EPA explains how the BSER forms the basis for each state's overall emission limitation requirement, which the EPA determines as the state goal and the state adopts into its planning process as the emissions performance level. The emission performance level, in turn, constitutes the minimum degree of stringency for the standards of performance that, taken as a whole, the state must establish for its affected EGUs (or, if the state adopts the portfolio approach, for the requirements imposed on the affected EGUs and other entities). Through this process, the BSER informs the minimum stringency of the standards of performance, although the state retains flexibility in its allocation of emission limitations among its sources. As the EPA explains, central to this overall approach is the fact that the EPA applies the BSER on a state-wide basis, which is consistent with the interconnected nature of the electricity system.

The EPA is proposing two alternative formulations for the BSER, each of which is based on, although in different ways, the four building blocks. Under the first approach, emission rate improvements and mass emission reductions at affected EGUs facilitated through the adoption of the four building blocks themselves meet the criteria for the BSER because they will amount to substantial reductions in CO_2 emissions achieved while maintaining fuel diversity and a reliable, affordable electricity supply for the United States. Under the second approach, the BSER consists of building block 1 coupled with reduced utilization in specified amounts from, in general, higher-emitting affected EGUs. Under this latter approach, the measures in building blocks 2, 3, and 4 serve to justify those amounts and the ''adequate[ ] demonstrat[ion]'' because they are proven measures that are already being pursued by states and the industry, at least in part for the purpose of reducing CO_2 emissions from affected EGUs.

The remainder of this discussion is organized into the following subsections. Subsection 2 contains a summary of relevant considerations for the BSER as defined in the statute and further interpreted in court decisions. Subsection 3 discusses characteristics of the electricity industry relevant to

interpretation of the BSER for purposes of this proposal, most notably the industry's highly interconnected and integrated nature. Subsection 4 provides a discussion of how the building blocks would satisfy the BSER criteria in isolation or support the alternative formulation of the BSER as including reduced utilization in specified amounts. Subsection 5 evaluates two combinations of building blocks—a combination of building blocks 1 and 2, and the proposed combination of all four building blocks—against the BSER criteria, and explains why we propose that the combination of all four is the BSER. Subsection 6 addresses additional considerations related to the inclusion of building blocks 2, 3, and 4 as parts of the basis supporting the BSER. In subsection 7, we describe and seek comment on the alternate interpretation that the BSER includes, in addition to building block 1, a component consisting of reduced generation from higher-emitting affected EGUs, with the measures in the other building blocks serving as the basis for quantifying the amounts of generation reductions and consequent CO_2 emission reductions that can be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. In subsection 8, we discuss the discretion that the case law gives us in weighing the various criteria to determine the BSER. In subsection 9, we discuss how the BSER and the state-wide manner in which the EPA applies it form the basis for the emission standards that the state includes in the plan, and we explain why that approach is consistent with the applicable section 111 requirements. The final three subsections address the topics of combining source categories, severability, and certain other specific issues on which we are seeking comment. Additional discussion is provided in the Legal Memorandum available in the docket.

2. Statutory and Regulatory Provisions Related to Determination and Application of the BSER

The EPA's explanation for this BSER proposal begins with the statutory definition of a ''standard of performance'':

The term ''standard of performance'' means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.

42 U.S.C. 7411(a)(1).

The U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit or Court) has handed down case law over a 40-year period that interprets this CAA provision, including its component elements.[194] Under this case law, the EPA determines the BSER based on the following key considerations, among others:

- The system of emission reduction must be technically feasible.
- The EPA must consider the amount of emission reductions that the system would generate.
- The costs of the system must be reasonable. The EPA may consider costs at the source level, the industry level, and, at least in the case of the power sector, the national level in terms of the overall costs of electricity and the impact on the national economy over time.[195]
- The EPA must also consider that CAA section 111 is designed to promote the development and implementation of technology, including the diffusion of existing technology as the BSER,[196] the development of new technology that may be treated as the BSER,[197] and the development of other emerging technology.[198]

Another consideration particularly relevant to this rulemaking is energy impacts, which, as with costs, the EPA may consider at the source level, the industry level, and the national level over time. In the context of the electricity industry and this proposal, the EPA believes that the scope of energy impacts that may be considered encompasses assurance of the continued ability of the industry to meet the evolving demand for electricity services in a reliable manner, while providing sufficient flexibility to enable affected sources to follow state energy plans.

Importantly, the EPA has discretion to weigh these various considerations, may determine that some merit greater weight than others, and may vary the weighting depending on the source category.

It is a well-established principle that states have discretion regarding the measures adopted in their state implementation plans under CAA section 110 to attain the NAAQS.[199] The EPA believes that the same principle applies in the context of state plans under section 111(d) as well, such that each state has the discretion to adopt emission reduction measures other than the measures found by the EPA to comprise the BSER, or to place greater or lesser emphasis than the EPA on certain measures, provided that the state's plan achieves the required level of emission performance for affected sources.

The EPA discussed the CAA requirements and Court interpretations of the BSER at length in the January 2014 Proposal, 79 FR at 1,462/1–1,467/3, and incorporates by reference that discussion into this rulemaking.

Over the last forty years, under CAA section 111(d), the agency has regulated four pollutants from five source categories (i.e., phosphate fertilizer plants (fluorides), sulfuric acid plants (acid mist), primary aluminum plants (fluorides), Kraft pulp plants (total reduced sulfur), and municipal solid waste landfills (landfill gases)).[200] In addition, the agency has regulated additional pollutants under CAA

[194] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973), cert. denied, 416 U.S. 969 (1974); *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973), cert. denied, *Appalachian Power Co.* v. *EPA,* 416 U.S. 969 (1974); *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981); *Portland Cement Ass'n* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011). Although this case law concerns the meaning of the definition of ''standard of performance'' for purposes of rulemakings that the EPA promulgated under CAA section 111(b), the same term is used for section 111(d), and as a result, this case law is relevant for the present rulemaking under section 111(d).

[195] As discussed in the January 2014 Proposal, the D.C. Circuit's case law formulates the cost consideration in various ways: The costs must not be ''exorbitant[ ]'', *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d at 433, see *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999); ''greater than the industry could bear and survive,'' *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975); or ''excessive'' or ''unreasonable,'' *Sierra Club* v. *Costle,* 657 F.2d at 343. In the January 2014 Proposal, the EPA stated that ''these various formulations of the cost standard . . . are synonymous,'' and, for convenience, we used ''reasonableness'' as the formulation. We take the same approach in this rulemaking.

[196] *See* 1970 Senate Committee Report No. 91–1196 at 15 (''The maximum use of available means of preventing and controlling air pollution is essential to the elimination of new pollution problems'').

[197] *See Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d at 391 (the best system of emission reduction must ''look[ ] toward what may fairly be projected for the regulated future, rather than the state of the art at present'').

[198] *See Sierra Club* v. *Costle,* 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

[199] *See Train* v. *Natural Res. Def. Council,* 421 U.S. 60 (1975).

[200] *See* ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12022 (Mar. 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55796 (Oct. 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26294 (Apr. 17, 1980); ''Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule,'' 61 FR 9905 (Mar. 12, 1996).

section 111(d) in conjunction with CAA section 129.[201] However, the agency has not previously regulated CO_2 or any other greenhouse gas under CAA section 111(d) (although because landfill gases include methane, the agency's regulation of landfill gases reduced emissions of that greenhouse gas). Further, the electricity industry differs in important ways from the source categories previously regulated under section 111(d) in terms of its large scale, its central importance to the economy, and, as discussed below, its highly interconnected and integrated nature.

3. The Interconnected Nature of the U.S. Electricity Sector

The U.S. electricity system is a highly interconnected, integrated system in which large numbers of EGUs using diverse fuels and generating technologies are operated in a coordinated manner to produce fungible electricity services for customers. Because electricity storage is costly and has not been widely deployed, the amounts of electricity demanded and supplied must be continuously matched, and system operators typically have flexibility to choose among multiple EGUs when selecting where to obtain the next MWh of generation needed. Coordination over short- and long-term time scales is accomplished through a variety of institutions including vertically integrated utilities, state regulatory agencies, independent system operators and regional transmission organizations (ISOs/RTOs), and market mechanisms. The electricity sector is both critical to the nation's economy and the source of more than 30 percent of U.S. greenhouse gas emissions, predominantly in the form of CO_2.

The integrated electricity system allows increased generation from less carbon-intensive NGCC units to substitute for generation from more carbon-intensive steam EGUs (building block 2), thereby lowering CO_2 emissions from the group of affected EGUs as a whole. The electricity system similarly allows increased generation resulting from expansion of the amount of available low- or zero-carbon generating capacity connected to the electric grid (building block 3), as well as avoided generation resulting from reductions in electricity demand (building block 4), to substitute for fossil fuel-fired generation, thereby reducing CO_2 emissions from affected EGUs. Each of these measures already routinely occurs within this integrated system for providing electricity and electricity services.

The integrated nature of the electricity system has long played a central role in the industry's continuing efforts to assure reliability and to manage costs generally. Specifically in the area of pollution control, state governments and the federal government have repeatedly taken advantage of the integrated nature of the electricity system when designing programs to allow the industry to meet the pollution control objectives in a least-cost manner. Examples include several cap-and-trade programs to reduce national or regional emissions of SO_2 and NO_X: The SO_2-related portion of the CAA Title IV Acid Rain Program, the Ozone Transport Commission (OTC) NO_X Budget Program, the NO_X SIP Call NO_X Budget Trading Program, and the Clean Air Interstate Rule (CAIR) annual SO_2, annual NO_X, and ozone-season NO_X trading programs. While the Acid Rain Program was created by federal legislation, the OTC NO_X Budget Program was developed primarily through the joint efforts of a group of northeastern states. In the NO_X SIP Call and CAIR programs, the federal government set emission budgets and developed trading programs that states could use as a compliance option.[202] Each of these programs was designed to take advantage of the fact that in an integrated electricity system, some EGUs can reduce emissions at lower costs than others, and that by allowing the industry to determine through market mechanisms which EGUs to control and which to leave uncontrolled, and which EGUs to potentially operate more and which to potentially operate less, overall compliance costs can be reduced. The integrated electricity system plays the important function of allowing some EGUs to reduce their generation while ensuring that overall demand for electricity services can be reliably met. It is worth noting that adoption by affected EGUs of any of the measures in the building blocks could be (or could have been) used to facilitate compliance with each of the programs just described.[203]

Some states are already relying on the integrated nature of the electricity system to establish the policy contexts within which affected EGUs will reduce their CO_2 emissions.[204] California and Colorado provide two examples of how statewide targets (or company-wide targets within a state) can be designed with consideration of the wide range of CO_2 mitigation options and affected EGUs' flexibility to use those options.

California enacted its Global Warming Solutions Act (also known as AB32) in 2006, requiring the state to reduce its GHG emissions to 1990 levels by 2020 and 80 percent below 1990 levels by 2050.[205] According to California, ''the integrated nature of the power grid means that policies which displace the need for fossil generation can often cut emissions from covered sources more deeply, and more cost-effectively than can engineering changes at the plants alone, though these source-level control efforts are a vital starting point.'' [206] California therefore relied on a suite of mechanisms to provide fossil fuel-fired generation substitutes and incentives for EGUs to reduce their emissions, including demand-side energy efficiency programs, renewable energy programs, and an economy-wide cap-and-trade program, along with other programs.[207] The California plan has put in place mechanisms that through market dynamics affect both companies' longer-term planning decisions and their short-term dispatch decisions. The need to hold emissions allowances and the reduced demand from demand-side energy efficiency programs impact longer-term decisions companies make about investment in both existing and new EGUs. The price of emission allowances also impacts hourly dispatch decisions; where emission allowance requirements are in effect, EGU owners

[201] *See, e.g.,* ''Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Sewage Sludge Incineration Units, Final Rule,'' 76 FR 15372 (Mar. 21, 2011).

[202] In the Regional Greenhouse Gas Initiative, described in more detail below, participating states use emission budgets and a trading program to address CO_2 emissions from the electricity sector.

[203] In addition to the already-implemented programs mentioned above—the SO_2-related portion of the Acid Rain Program, the OTC NO_X Budget Program, the NO_X SIP Call NO_X Budget Trading Program, and the Clean Air Interstate Rule trading programs—use of measures in the building blocks would also facilitate compliance with the cap-and-trade programs established by the Cross-State Air Pollution Rule (76 FR 48208, Aug. 8, 2011).

[204] A number of utilities also have climate mitigation plans. Examples include National Grid, *http://www2.nationalgrid.com/responsibility/how-were-doing/grid-data-centre/climate-change/*; Exelon, *http://www.exeloncorp.com/newsroom/pr_20140423_EXC_Exelon2020.aspx*; PG&E, *http://www.pge.com/about/environment/pge/climate/*; and Austin Energy, *http://austinenergy.com/wps/portal/ae/about/environment/austin-climate-protection-plan/!ut/p/a0/04_Sj9CPykssy0xPLMnMz0vMAfGjzOINjCyMPJwNjDzdzY0sDBzdnZ28TcP8DAMMDPQLsh0VAU4fG7s!/.*

[205] State of California Global Warming Solutions Act of 2006, Assembly Bill 32, *http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf.*

[206] December 27, 2013 Letter from Mary D. Nichols, Chairman of California Air Resources Board, to EPA Administrator Gina McCarthy.

[207] See Cal. Air Res. Bd., Climate Change Scoping Plan 31–32, 41–46 (2008), available at *http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf.*

routinely recognize the costs of emission allowances as components of the variable operating costs that are relied on for these decisions.[208] In this manner, allowance prices constitute market signals encouraging reduced use of higher-emitting EGUs and increased use of lower-emitting EGUs.

The Colorado Clean Air, Clean Jobs Act (CACJA), signed into law on April 19, 2010, required each investor-owned utility with coal-fired EGUs to submit to the state a multi-pollutant plan for meeting current and foreseeable EPA standards for emissions of NO_X, SO_2, particulates, mercury, and CO_2. Rather than fully prescribing specific control technologies, the law provided flexibility for each utility to select the best set of measures to achieve the emission reductions.[209] For example, a utility could choose to retrofit or repower EGUs, or it could choose to retire higher-emitting EGUs and replace them with NGCC units and other low- or non-emitting energy plants or with end-use efficiency measures.[210] The Colorado plan generally focused more on impacting companies' longer-term planning decisions than on affecting short-term dispatch decisions. In response, Colorado utilities have adopted a mix of measures including retrofits, natural gas conversions and retirements of coal-fired EGUs, as well as construction of new NGCC units.

Multi-state mechanisms with analogous impacts on both longer-term planning decisions and short-term dispatch decisions have also been put in place. For example, nine northeastern and Mid-Atlantic States [211] participate in the Regional Greenhouse Gas Initiative (RGGI), a market-based emissions budget trading program that sets an aggregate limit on CO_2 emissions from fossil fuel-fired EGUs in the participating states. To comply with the program, each EGU must acquire allowances equal to its emissions in each compliance period—through purchases or by allocation from the state—and must surrender the allowances at the end of the period. The RGGI program offers flexibility to regulated parties through provisions for multi-year compliance periods, allowance banking, offsets, an auction reserve price, and a cost-containment reserve of allowances, and further encourages emission allowance market development by authorizing trading between regulated and non-regulated parties.[212] Operating in this regime, EGUs could take a variety of compliance actions, including replacing generation at higher-emitting EGUs with generation at lower-emitting EGUs or achieving emissions reductions at EGUs by means of end-use energy efficiency programs.

An approach to determination of the BSER that recognizes the integrated nature of the electricity system is also consistent with the way in which the electricity industry already addresses resource planning issues. For example, in states where the price of EGUs' generation remains subject to regulation, utilities generally prepare integrated resource plans setting forth their strategies for meeting future demand for electricity services in a cost-effective manner. These plans may include measures from building blocks 2, 3, and 4. In most states where generation is no longer subject to price regulation, regional transmission organizations (RTOs) or independent system operators (ISOs) ensure the adequacy of future generation supplies by administering auctions for forward capacity. In these auctions, owners of existing EGUs (with consideration of building blocks 1 and 2),[213] developers of new EGUs including renewable generating capacity (building block 3), and developers of demand-side resources (building block 4) all compete to provide potential resources for meeting the projected demand for electricity services.

As indicated by the foregoing discussion, in the U.S. electricity system the demand for electricity services is met, on both a short-term and longer-term basis and in both regulated and deregulated contexts, through integrated consideration of a wide variety of possible options, coordinated by some combination of utilities, regulators, system operators, and market mechanisms. The EPA believes that the BSER for CO_2 emissions from existing EGUs should reflect this integrated character.

A final, important point regarding the integrated electricity system is that the sets of actions that enable the demand for electricity services to be continuously met can be undertaken in different orders, with changes in some interconnected elements eliciting compensating responses from other interconnected elements. Thus, the CO_2 emissions reductions associated with building blocks 2, 3, and 4 can be achieved in either of two ways: (i) First instituting measures in building blocks 2, 3, and 4, which, due to the interconnected and integrated nature of the grid, would elicit the response of reducing generation at some or all affected EGUs, thereby lowering those EGUs' emissions; or (ii) first reducing generation and therefore emissions from some or all affected EGUs (or planning to make those reductions), which due to the interconnected and integrated nature of the grid, would elicit the responses identified in building blocks 2, 3, and 4 of increasing generation at lower-emitting EGUs or reducing the demand for electricity services. (In some cases, the change and response could be planned simultaneously.) Each of these sets of actions, with the building blocks as the initial change or the reduced generation at affected EGUs as the initial change, may be considered to be part of a ''system of emission reduction,'' as discussed below.

Further discussion of the ways in which the ''system of emission reduction'' for affected EGUs is influenced by the interconnected and integrated nature of the electricity system is provided below in the context of the EPA's rationale for proposing to base the BSER on the combination of all four building blocks. This topic is also discussed in the Legal Memorandum available in the docket.

4. Evaluation of Individual Building Blocks Against the BSER Criteria

In this subsection we explain why (i) the individual building blocks meet the criteria to qualify as components of the ''best system of emission reduction . . . adequately demonstrated'' and (ii) why, under the alternative formulation of the BSER as including reduced utilization of higher-emitting affected EGUs in specified amounts, building blocks 2, 3, and 4 serve as the basis for those amounts and why the reduced utilization is ''adequately demonstrated.''

a. Building Block 1—Heat Rate Improvements

Building block 1—reducing the carbon intensity of generation at individual affected coal-fired steam EGUs through heat rate improvements—is a component of the BSER because the measures the affected sources may

[208] The requirement to hold allowances covering their CO_2 emissions went into effect for EGUs in California on January 1, 2013.

[209] The law also set some explicit requirements, such as requirements for development of new renewable generating capacity and requirements to phase out older coal-fired EGUs.

[210] See State of Colorado House Bill 10–1365, available at *http://www.leg.state.co.us/clics/clics2010a/csl.nsf/fsbillcont/0CA296732C8CEF4D872576E400641B74?Open&file=1365_ren.pdf.*

[211] Participating states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

[212] See RGGI Web site at *http://www.rggi.org/rggi.*

[213] Potential heat rate improvements create opportunities for EGU owners to reduce their variable costs, which increase potential operating profits from generation and thereby create opportunities to lower the prices at which the owners would bid the capacity of their EGUs into the auctions.

undertake to achieve heat rate improvements are technically feasible and of reasonable cost, and meet the other requirements to qualify as a component of the ''best system of emission reduction . . . adequately demonstrated.''

The EPA's analysis and conclusions regarding the technical feasibility, costs, and magnitude of CO_2 emission reductions achievable through heat rate improvements are discussed in Section VI.C.1 above. We consider heat rate improvement to be a common and well-established practice within the industry.

Other BSER criteria also favor building block 1 as a component of the BSER. For example, with respect to non-air health and environmental impacts, heat rate improvements cause fuel to be used more efficiently, reducing the volumes of and therefore the adverse impacts associated with disposal of coal combustion solid waste products. With respect to technological innovation, building block 1 encourages the spread of more advanced technology to EGUs currently using components with older designs. The EPA has not specifically evaluated the extent to which enhanced maintenance practices leading to heat rate improvements might also lead to electricity reliability improvements, but generally expects that enhanced maintenance would be more likely to improve than to degrade EGU availability, which would tend to improve electricity system reliability.

As noted above, the EPA is concerned about the potential ''rebound effect'' associated with building block 1 if applied in isolation. More specifically, we noted that in the context of the integrated electricity system, absent other incentives to reduce generation and CO_2 emissions from coal-fired EGUs, heat rate improvements and consequent variable cost reductions at those EGUs would cause them to become more competitive compared to other EGUs and increase their generation, leading to smaller overall reductions in CO_2 emissions (depending on the CO_2 emission rates of the displaced generating capacity). However, we believe that this concern can be readily addressed by ensuring that the BSER also reflects other CO_2 reduction strategies that encourage increases in generation from lower- or zero-carbon EGUs or in demand-side energy efficiency, thereby allowing building block 1 to be considered part of the BSER for CO_2 emissions at affected EGUs.

b. Building Block 2—Re-Dispatch

Building block 2—reducing CO_2 emissions at and substituting for generation from the most carbon-intensive affected EGUs with generation from less carbon-intensive affected EGUs (specifically NGCC units that are currently operating or under construction)—is a component of the BSER because the shifts in generation that it involves demonstrate that reducing mass CO_2 emissions at higher-emitting EGUs is technically feasible, will not jeopardize system reliability, is of reasonable cost, and meets the other requirements for a component of the ''best system of emission reduction . . . adequately demonstrated.''

The EPA's analysis and conclusions regarding the technical feasibility, costs, and magnitude of CO_2 emission reductions achievable at high-emitting EGUs through re-dispatch among affected EGUs are discussed in Section VI.C.2 above. We consider re-dispatch among the large number of diverse EGUs that are linked to one another and to customers by extensive regional transmission grids to be a routine and well-established operating practice within the industry that is used to facilitate the achievement of a wide variety of objectives, including environmental objectives, while meeting the demand for electricity services. As discussed above, in the interconnected and integrated electricity industry, fossil fuel-fired steam EGUs are able to reduce their generation and NGCC units are able to increase their generation in a coordinated manner through mechanisms—in some cases centralized and in others not—that regularly deal with such changes on both a short-term and a longer-term basis.

Both the achievability of this building block and the reasonableness of its costs are supported by the fact that there has been a long-term trend in the industry away from coal-fired generation and toward NGCC generation for a variety of reasons. As part of their CO_2 reduction strategies, states can encourage this trend in a variety of ways. First, a state could use its permitting authority to impose limits on the hours of operation (or emissions) of individual steam generating units over a given time period. Second, a state could change the relative costs of generation for more carbon-intensive and less carbon-intensive generating units by imposing a cost on carbon emissions. A state could do so through any of several market-based mechanisms. One would be to adopt an allowance-based system. An example is the Regional Greenhouse Gas Initiative, an allowance-based system in which sources purchase allowances in periodic auctions. Another way would be through a tradable emission rate system, under which the state would impose an emission rate limit on the steam generating unit that the unit could meet only by purchasing the right to average its emission rate with a unit with a lower rate, such as an NGCC unit. Most broadly, an allowance system would provide the greatest incentive for the most carbon-intensive affected sources to reduce emissions as much as possible so as to reduce their need to purchase allowances (or to allow them to sell un-needed allowances), and the same would be true for a tradable emission rate system.

The emission reductions achievable or supported by the application of building block 2 also perform well against other BSER criteria. For example, we expect that building block 2 would have positive non-air health and environmental impacts. Coal combustion for electricity generation produces large volumes of solid wastes that require disposal, with some potential for adverse environmental impacts; these wastes are not produced by natural gas combustion. The intake and discharge of water for cooling at many EGUs also carries some potential for adverse environmental impacts; NGCC units generally require less cooling water than steam EGUs.[214] As already noted, with respect to energy impacts, the EPA believes that building block 2 (at least at the level of stringency proposed for purposes of establishing state goals) would not pose risks to reliability. Building block 2 also promotes greater use of the advanced NGCC technology installed in the existing fleet of NGCC units.

It should be observed that, by definition of the elements of this building block, the shifts in generation taking place under building block 2 occur entirely among existing EGUs subject to this rulemaking.[215] Through application of this building block considered in isolation, some affected sources—mostly coal-fired steam EGUs—would reduce their generation and CO_2 emissions, while other affected sources—NGCC units—would increase their generation and CO_2 emissions.[216]

[214] According to a DOE/NETL study, the relative amount of water consumption for a new pulverized coal plant is 2.5 times the consumption for a new NGCC unit of similar size. ''Cost and Performance Baseline for Fossil Energy Plants: Volume 1: Bituminous Coal and Natural Gas to Electricity,'' Rev 2a, September 2013, National Energy Technology Laboratory Report DOE/NETL–2010/1397.

[215] For purposes of this rulemaking, ''existing'' EGUs include units under construction as of January 8, 2014, the date of publication in the **Federal Register** of the Carbon Pollution Standards for new fossil fuel-fired EGUs.

[216] Because building blocks 3 and 4 reduce generation and CO_2 emissions from all fossil fuel-

However, because for each MWh of generation, NGCC units produce less CO_2 emissions than coal-fired steam EGUs, the total quantity of CO_2 emissions from all affected sources in aggregate would decrease. In the context of the integrated electricity system, where the operation of affected EGUs of multiple types is routinely coordinated to provide a fungible service, and in the context of CO_2 emissions, where location is a less important factor than is the case for other pollutants, the EPA believes that a measure that takes advantage of that integration to reduce CO_2 emissions from the overall set of affected EGUs is readily encompassed within the meaning of a ''system of emission reduction'' for CO_2 emissions at affected EGUs even if the measure would increase CO_2 emissions from a subset of those affected EGUs. Indeed, our review of the data and discussions with states reveal that some states are already moving in this direction for this purpose (while others are moving in the same direction for other purposes). Emission trading or averaging approaches can facilitate the implementation of such a ''system'' and have already been used in the electricity industry to address CO_2 as well as other pollutants, as discussed above.

Finally, the EPA notes that the alternative interpretation of the BSER discussed later is based in part on the re-dispatch measures in building block 2. In this alternative, as it relates to building block 2, reduced generation from the subset of affected EGUs consisting of fossil fuel-fired steam EGUs—i.e., the most carbon-intensive subset of affected EGUs—is a component of the BSER. The potential to use increased generation from less carbon-intensive affected NGCC units would serve as a basis for quantifying the amounts of generation reductions and CO_2 emission reductions at more carbon-intensive affected EGUs that could be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. This alternative is discussed further in Section VI.E.7 below.

c. Building Block 3—Use of Expanded Low- and Zero-Carbon Generating Capacity

Building block 3—reducing CO_2 emissions at and substituting for generation from affected EGUs by using expanded amounts of low- and zero-carbon generating capacity—is a component of the BSER because the expansion and use of renewable generating capacity, completion and use of nuclear capacity currently under construction, and avoidance of nuclear capacity retirements all establish the foundation for a determination that mass emission reductions from affected EGUs are technically feasible, do not jeopardize system reliability, are of reasonable cost, and meet the other requirements for a component of the ''best system of emission reduction . . . adequately demonstrated.''

The EPA's analysis and conclusions regarding the technical feasibility, costs, and magnitude of the measures in building block 3 are discussed in Section VI.C.3 above. We consider all of these measures to be proven, well-established practices within the industry, and development of renewable capacity in particular is consistent with recent industry trends. States are already pursuing policies that encourage production of greater amounts of renewable energy, such as the establishment of targets for procurement of renewable generating capacity. Moreover, markets for renewable energy certificates, which facilitate investment in renewable energy, are already well-established. As noted above with re-dispatch, an allowance system or tradable emission rate system would provide incentives for sources to reduce their emissions as much as possible, including through substituting for their generation with generation from renewable energy. In addition, owners of existing nuclear units and nuclear units currently under construction can take action to complete or preserve that capacity, the generation from which likewise can be dispatched in a coordinated manner to substitute for fossil fuel-fired generation. As discussed above, coordination of these decisions in the integrated electricity system can occur through a variety of mechanisms, some centralized and some not.

The renewable capacity measures in building block 3 generally perform well against other BSER criteria. For example, incentives for expansion of renewable capacity encourage technological innovation in improved renewable technologies as well as more extensive deployment of current advanced technologies. Generation from wind turbines (the most common renewable technology) does not produce solid waste or require cooling water, a better environmental outcome than if that amount of generation had instead been produced at a typical range of fossil fuel-fired EGUs. Although the intermittent nature of generation from renewable resources such as wind and solar units requires special consideration from grid operators, renewable generation has grown quickly in recent years, as discussed above, and the EPA has seen no evidence that operators will be less able to cope with future growth than they have with rapid past growth.

The EPA believes that the performance of the nuclear measures in building block 3 against the other BSER measures is also positive on balance. With respect to encouragement of technological innovation, incentives for completion of nuclear capacity currently under construction encourage deployment of nuclear unit designs that reflect advances over earlier designs. The nation's nuclear fleet today routinely operates at high average utilization rates, suggesting no reason to expect adverse reliability consequences from completion or preservation of additional nuclear capacity. The five nuclear units currently under construction are all designed to use closed-cycle cooling systems with lower cooling water usage than some existing fossil fuel-fired EGUs;[217] existing nuclear units may use amounts of cooling water comparable to the amounts used by those fossil fuel-fired steam EGUs. The EPA recognizes that nuclear generation poses unique waste disposal issues (although it avoids the solid waste issues specific to coal-fired generation). However, we do not consider that potential disadvantage of nuclear generation relative to fossil fuel-fired generation as outweighing nuclear generation's other advantages as an element of building block 3. For all these reasons, we consider building block 3 to be a component of the ''best system of emission reduction . . . adequately demonstrated.''

Finally, the EPA notes that the alternative BSER discussed later would include a component consisting of reduced generation from affected EGUs,

fired affected EGUs as a group, including NGCC units, the increase in generation and CO_2 emissions from NGCC units under building block 2 is mitigated to some extent by including those building blocks in the BSER along with building block 2.

[217] *See* U.S. NRC, Watts Bar Unit 2 Final Environmental Statement, Final Report at 3–3, available at *http://pbadupws.nrc.gov/docs/ML1314/ML13144A092.pdf;* U.S. NRC, Summer Units 2–3 Final Environmental Impact Statement, Final Report at 3–14, available at *http://pbadupws.nrc.gov/docs/ML1109/ML11098A044.pdf*; U.S. NRC, Vogtle Units 3–4 Final Environmental Impact Statement, Final Report at 3–5, available at *http://pbadupws.nrc.gov/docs/ML0822/ML082240145.pdf*. Relative to the once-through systems at many existing power plants, closed-cycle cooling systems withdraw from and discharge to external water bodies substantially less overall cooling water, although they also consume larger amounts of water through evaporation. *See* Department of Energy/Office of Fossil Energy's Power Plant Water Management R&D Program, available at *http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/PowerPlantWaterMgtR-D-Final-1.pdf.*

with the measures in building block 3 serving as a basis for quantifying the amount of reduced generation and consequent CO_2 emission reductions. Because of the availability of those measures, the amount of reduced generation can be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. This alternative BSER is discussed in Section VI.E.7 below.

d. Building Block 4—Increased Demand-Side Energy Efficiency

Building block 4—reducing CO_2 emissions at and reducing generation from affected EGUs by promoting demand-side energy efficiency that reduces the amount of generation required from affected EGUs—is a component of the BSER because the demand-side energy efficiency is technically feasible and of reasonable cost, and meets the other requirements for a component of the ''best system of emission reduction . . . adequately demonstrated.''

The EPA's analysis and conclusions regarding the technical feasibility, costs, and magnitude of building block 4 are discussed in Section VI.C.4 above. We consider demand-side energy efficiency programs to be proven, well-established practices within the industry that are consistent with industry trends. Greater demand-side energy efficiency is already a common policy goal among states, and most states already authorize or require implementation of demand-side energy efficiency programs. Fossil fuel-fired EGUs can reduce their generation. Owners of affected EGUs as well as other parties can contract for demand-side energy efficiency. As discussed above, coordination of these decisions in the integrated electricity system can occur through a variety of mechanisms, some centralized and some not. For example, an allowance system or tradable emission rate system would provide incentives that promote the measures in building block 4 in the same manner as discussed above for other building blocks.

Building block 4 is also very attractive under other BSER criteria. Demand-side energy efficiency avoids the non-air health and environmental effects of the fossil fuel-fired generation for which it substitutes. Further, by reducing the overall amount of electricity that needs to be transmitted between EGUs and customers, demand-side energy efficiency tends to relieve stress on the grid, thereby increasing system reliability. Creating incentives for additional demand-side energy efficiency is also consistent with the goals of encouraging technological innovation in energy efficiency and encouraging deployment of current advanced technologies. For all these reasons, the measures in building block 4 qualify as a component of the ''best system of emission reduction . . . adequately demonstrated.''

The EPA notes that the alternative BSER discussed later would include a component consisting of reduced generation from affected EGUs, with demand-side energy efficiency serving as a basis for quantifying the amounts of generation reductions and consequent CO_2 emission reductions that can be achieved while continuing to meet the demand for electricity services in a reliable and affordable manner. This alternate interpretation of the BSER is discussed in Section VI.E.7 below.

5. Evaluation of Building Block Combinations Against the BSER Criteria

a. Combination of Building Blocks 1 and 2

The EPA has considered whether a combination of building blocks 1 and 2 would be the BSER. As described in Section VI.D above, we believe that such a combination is technically feasible and would be a ''system of emission reduction'' capable of achieving meaningful reductions in CO_2 emissions from affected EGUs at a reasonable cost. The combination would also satisfy other BSER criteria. Nevertheless, we do not propose that this combination should be the BSER because the proposed combination of all four building blocks is capable of achieving greater reductions in CO_2 emissions from affected EGUs at a lower cost.

The EPA believes that both building blocks 1 and 2 individually satisfy the BSER criteria identified by the statute and the D.C. Circuit, with one possible concern, related to a ''rebound effect,'' noted earlier. That concern is the potential for the heat rate improvements in building block 1, if implemented in isolation, to make coal-fired steam EGUs more competitive compared to other EGUs and cause them to increase their generation, creating a ''rebound effect'' that would make building block 1 less effective at reducing CO_2 emissions. As discussed above, building blocks 1 and 2 each appear attractive or neutral with respect to each of the other BSER criteria.

With respect to most of the BSER criteria, there is no reason to expect that the combination of building blocks 1 and 2 would be evaluated differently from the individual building blocks. However, as noted earlier, the combination addresses the concern about building block 1 regarding a potential rebound effect, and in that important respect it performs better than building block 1 considered in isolation. The substitution of NGCC generation for generation from coal-fired and other steam EGUs ensures that generation from coal-fired EGUs, as a group, would not increase as a result of their improved variable costs, with the result that the reduction in CO_2 emission rates of coal-fired EGUs brought about by heat rate improvements would not be offset by an increase in CO_2 emissions due to increased generation from those EGUs. The combination of building blocks would therefore be capable of achieving greater reductions in CO_2 emissions from affected sources than either building block in isolation.

While achieving substantially greater emission reductions than building block 1 alone, by reducing overall generation from coal-fired EGUs the combination of building blocks 1 and 2 also has the potential to raise the cost of the portion of the overall emission reductions achievable through heat rate improvements relative to the cost of those reductions if building block 1 were implemented in isolation.[218] However, the EPA believes that the cost of emission reductions achieved through heat rate improvements would remain reasonable for two reasons. First, as discussed in Section VI.C.1 above, the cost of CO_2 emission reductions achievable through heat rate improvements is quite low, and that cost would remain reasonable even if it was substantially increased. Second, although under the combination of building blocks 1 and 2 the volume of coal-fired generation would decrease, that decrease is unlikely to be spread uniformly among all coal-fired EGUs. It is more likely that some coal-fired EGUs would decrease their generation slightly while others would decrease their generation by larger percentages or cease operations altogether. We would expect EGU owners to take these changes in EGU operating patterns into account when considering where to invest in heat rate improvements, with the result that there would be a tendency for such investments to be concentrated in EGUs whose generation output was expected to decrease the

[218] If an EGU produces less generation output, then an improvement in that EGU's heat rate and rate of CO_2 emissions per unit of generation produces a smaller reduction in CO_2 emissions. If the investment required to achieve the improvement in heat rate and emission rate is the same regardless of the EGU's generation output, then the cost per unit of CO_2 emission reduction will be higher when the EGU's generation output is lower.

least. This enlightened bias in spending on heat rate improvements—that is, focusing investments on EGUs where such improvements would have the largest impacts and produce the highest returns, given consideration of projected changes in dispatch patterns—would tend to mitigate any deterioration in the cost of CO_2 emission reductions achievable through heat rate improvements.

As noted above, the EPA invites comment on a potential BSER comprising building blocks 1 and 2, in light of the considerations that could support this approach.

b. Combination of All Four Building Blocks

The EPA's proposed BSER is a combination of all four building blocks. For the reasons described below, and similar to each of the building blocks, the combination must be considered a ''system of emission reduction.'' Moreover, as also discussed below, the combination qualifies as the ''best'' system that is ''adequately demonstrated.'' The combination is technically feasible; it is capable of achieving meaningful reductions in CO_2 emissions from affected EGUs at a reasonable cost; it satisfies the other BSER criteria as well; and its components are well-established. The combination of all four building blocks would achieve greater CO_2 emission reductions at a lower cost than the combination of building blocks 1 and 2 described above, and would also perform better against other BSER criteria. We therefore propose to find the combination of all four building blocks to be the ''best system of emission reduction . . . adequately demonstrated'' for reducing CO emissions at affected EGUs.[219]

The assessments of the individual building blocks against the BSER criteria would generally apply in the same way to those building blocks when implemented as the combination of all four building blocks, with the same exceptions as discussed above with respect to the combination of building blocks 1 and 2 as well. However, the combination of all four building blocks would improve upon the combination of building blocks 1 and 2 in several respects. First, because of the potential of building blocks 3 and 4 to achieve additional CO_2 reductions at reasonable costs, the broader combination would achieve greater CO_2 emission reductions at a lower average cost. Second, by encompassing the increased low-and zero-carbon generation in building block 3, the broader combination would reduce reliance on fossil fuels and improve fuel diversity. Third, by encompassing the increased demand-side energy efficiency in building block 4, the broader combination would reduce the amount of electricity that would need to be delivered over the electric grid, generally reducing pressure on the grid and thereby improving electricity system reliability. These considerations all support basing the BSER on the combination of all four building blocks. They also support basing the BSER, in the alternative, on the combination of building block 1 and reduced generation in the amounts facilitated by the remaining building blocks.

As has been discussed in earlier portions of the preamble, the costs and energy impacts of each of the four building blocks individually are reasonable when viewed either at the individual source level or through the lens of the electricity system as a whole, a conclusion that holds for the combination of the building blocks as well. Moreover, the flexibility available to states and regulated entities to rely more extensively in their plans and strategies on whichever measures best suit their particular circumstances will further improve cost effectiveness. The analysis the EPA performed to assess the costs, benefits, and other impacts of the proposed goals reflects this compliance flexibility, along with transmission and pipeline capabilities and constraints, fuel market and electricity dispatch dynamics, and seasonal electricity load requirements. As described below in Section X, the results indicate that the proposed state goals (discussed in Section VII) are readily achievable with no adverse impacts on electricity system reliability, and that impacts on retail electricity prices are modest and fall within the range of price variability seen historically in response to changes in factors such as weather and fuel supply. Further, the costs tend to decline over time as states and regulated entities take advantage of the available flexibility and expand deployment of more cost-effective measures (notably demand-side energy efficiency). The EPA considers this analysis strong confirmation of the reasonableness of the costs of the measures in the four building blocks in combination as the best system of emission reduction.

6. Additional Considerations Related to Inclusion of Building Blocks 2, 3, and 4 as Part of the Basis Supporting the BSER

In this section, we discuss additional reasons why the measures in building blocks 2, 3, and 4, individually and in combination, meet the requirements to be components of the BSER. In particular, we discuss why they meet the definition of a ''system of emission reduction,'' and we provide additional reasons why they are the ''best'' that is ''adequately demonstrated.'' The interconnected nature of the electric system is an important part of our reasoning.

a. ''System of Emission Reduction''

For the convenience of the reader, it is useful to reiterate the key CAA section 111 requirements: Section 111(d)(1) requires that each state's plan ''establish[] standards of performance for any existing source'' for certain types of air pollutants; and section 111(a)(1) defines a ''standard of performance'' as ''a standard for emissions . . . which reflects the degree of emission limitation achievable through the application of the best system of emission reduction . . . adequately demonstrated.'' These provisions require that, in this rulemaking, the affected sources must be subject to emissions standards, but the basis for those standards—the ''system of emission reduction''—may be any method that reduces the affected sources' emissions, as long as that method is a ''system'' that meets the criteria for being the ''best'' that is ''adequately demonstrated.''

As discussed in the Legal Memorandum, the EPA is justified in adopting this interpretation under the first step of the framework for administrative agencies to construe statutes that the U.S. Supreme Court established in *Chevron U.S.A. Inc.* v. *NRDC,* 467 U.S. 837, 842–844 (1984) (*Chevron*), which we refer to as *Chevron* step 1.

Specifically, the term ''system,'' which is not defined in the CAA, is broad: ''A set of things working together as parts of a mechanism or interconnecting network.''[220] The

[219] The analysis of the interactions among building blocks provided above for the combination of building blocks 1 and 2, indicating that the addition of building block 2 would mitigate the potential concern about a ''rebound effect'' if building block 1 were implemented in isolation, applies to the combination of all four building blocks as well; in fact, the addition of building blocks 3 and 4 would further mitigate that concern. The EPA believes that if implemented in combination, each of the four building blocks would achieve substantial reductions in CO_2 emissions from affected EGUs at a reasonable cost.

[220] *Oxford Dictionary of English* (3rd ed.) (published 2010, online version 2013), *http://www.oxfordreference.com.mutex.gmu.edu/view/10.1093/acref/9780199571123.001.0001/acref-9780199571123.*

remaining provisions of the definition of ''standard of performance'' do not include any constraints on the ''set of things'' that may constitute a ''system of emission reduction.'' Nor does the context in which ''standard of performance'' is found—the provisions of section 111(d)(1)—add constraints on the things that may constitute such a system. Rather, it is clear from these CAA provisions that anything that reduces the emissions of affected sources may be considered a ''system of emission reduction'' for those sources. For this reason, the measures in building blocks 2, 3, and 4 must be considered components of such a system.

Even if these CAA provisions leave room for interpretation as to whether those measures must be considered components of such a system, the EPA's interpretation that they do is reasonable. As discussed in the Legal Memorandum, the EPA is justified in adopting this interpretation under the second step of the *Chevron* framework, which we refer to as *Chevron* step 2. There are several reasons. In enacting the CAA, Congress established ''pollution prevention'' as a ''primary goal'' of the Act, and described it as ''the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source.'' [221] Building blocks 2, 3, and 4 are pollution prevention measures, and, in light of the importance of pollution prevention in the CAA, it is reasonable to interpret ''system of emission reduction'' in section 111 to incorporate those measures. In addition, the breadth of ''system of emission reduction'' is confirmed by contrasting it with other provisions in the CAA that prescribe specific types of controls as the basis for emission limits.[222] Further support is found in Title IV of the CAA, in which Congress established the program that regulates fossil fuel-fired power plants to reduce their emissions of SO_2 and NO_X, the precursors to acid deposition. In designing Title IV, Congress recognized the integrated nature of the electricity sector and how that integration could be harnessed to reduce air pollutant emissions. In fact, Congress included provisions to encourage re-dispatch to lower-emitting sources, renewable energy, and demand-side energy efficiency, all of which are measures in those building blocks.[223] All this supports the reasonableness of interpreting ''system of emission reduction'' in CAA section 111 to incorporate those measures. It should also be noted that a number of commentators in the private sector and academia have indicated support for interpreting the term, ''system of emission reduction'' to base the CAA section 111(d) standards of performance on measures such as re-dispatch, renewable energy, and demand-side energy efficiency.[224] Some stakeholders have as well.[225]

b. ''Best'' System That Is ''Adequately Demonstrated

As described earlier with respect to the individual building blocks, the measures in each of building blocks 2, 3, and 4 meet the criteria for the ''best'' system of emission reduction, and, generally for the same reasons, the three in combination do as well.

In addition, the measures in building blocks 2, 3, and 4, individually and in combination, are ''adequately demonstrated.'' As discussed earlier, thanks to the integrated nature of the electricity system, they have long been relied on to reduce costs in general, assure reliability, and implement pre-existing pollution control requirements in the least-cost manner. As also noted elsewhere in the preamble, and discussed in more detail in the following subsections, some utilities, states and regions are already relying on these measures for the specific purpose of reducing CO_2 emissions from EGUs.

(i) Actions by Affected EGUs

Measures in building blocks 2, 3, and 4 may be undertaken or invested in by the affected EGUs themselves, which supports that these measures are ''adequately demonstrated.'' More specifically, the EPA believes that owners of units operating across a wide range of corporate, institutional and market structures (e.g., vertically integrated utilities in regulated markets, independent power producers, municipal utilities, and rural cooperatives) can take advantage of a broad range of reduction opportunities included in the building blocks. Because of the proposed lengthy planning period, owners can consider longer-term options such as implementing energy efficiency programs or replacement of older generating resources with more modern types of generation, as well as shorter-term options such as heat rate improvements and re-dispatch. Many companies, for example, already factor a carbon cost adder into their long-term planning decisions.

Large vertically integrated utilities generally have options within all four building blocks. They tend to have large and, as a general matter, at least somewhat diverse generation fleets. For their higher-emitting units, they have opportunities to use measures that reduce the units' CO_2 emission rates, such as heat rate improvements, co-firing, or fuel switching. While this proposal preserves fuel diversity, with over 30 percent of projected 2030 generation coming from coal and over 30 percent from natural gas, even companies that have traditionally depended upon coal to supply the majority of their generation are diversifying their fleets, increasing their

[221] CAA § 101(a)(3), (c).

[222] For example, as discussed in the Legal Memorandum, CAA § 407(b)(2) requires the EPA to base the nitrogen oxides (NO_X) emission limits for certain types of boilers ''on the degree of reduction achievable through the *retrofit* application of the best system of continuous emission reduction . . . ;'' and further requires the EPA to revise previously promulgated emission limits for certain types of boilers ''to be more stringent if the [EPA] determines that *more effective low NO_X burner technology* is available.'' (Emphasis added.)

[223] CAA § 401(b), 404(f)–(g).

[224] *See* Nordhaus R., Gutherz I., ''Regulation of CO_2 Emissions from Existing Power Plants Under § 111(d) of the Clean Air Act: Program Design and Statutory Authority,'' *Environmental Law Reporter,* 44: 10366, 10384 (May 2014) (''strong arguments for'' interpreting ''system'' to include measures such as the addition of new zero-carbon generating capacity and increases in end-user energy efficiency); Sussman R., ''Power Plant Regulation Under the Clean Air Act: A Breakthrough Moment for U.S. Climate Policy?'' *Virginia Environment Law Journal,* 32:97, 119 (2014) (''EPA would seem to have discretion to define 'system' to include any mix of strategies effective in reducing emissions.''); Konschnik K., Peskoe A., ''Efficiency Rules: The Case for End-Use Energy Efficiency Programs in the Section 111(d) Rule for Existing Power Plants,'' *Harvard Law School Environmental Law Program—Policy Initiative* 4 (March 3, 2014) (EPA is authorized to ''consider[ ] . . . the entire [electricity grid] system when setting performance standards.''); Monast J., Profeta T., Pearson B., Doyle J., ''Regulating Greenhouse Gas Emissions From Existing Sources: Section 111(d) and State Equivalency,'' Environmental Law Reporter, 42: 10206, 10209 (March 2012) (''Demand-side energy-efficiency programs and renewable energy generation may fit within the § 111 framework, however, because both reduce the utilization of power plant. . . . According to this reasoning, emission reductions are occurring within the source category, because of changes in generation at the power plant.'').

[225] Ceronsky M., Carbonell T., ''Section 111(d) of the Clean Air Act: The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants,'' *Environmental Defense Fund,* at 9 (Oct. 2013), *available at http://www.edf.org/sites/default/files/111-clean_air_act-strong_flexible_cost-effective_carbon_pollution_standards_for_existing_power_plants.pdf*; Doniger D., ''Questions and Answers on the EPA's Legal Authority to Set 'System Based' Carbon Pollution Standards for Existing Power Plants under Clean Air Act Section 111(d),'' *NRDC [Natural Resources Defense Council] Issue Brief* (Oct. 2013); ''Comments of the Attorneys General of New York, California, Massachusetts, Connecticut, Delaware, Maine, Maryland, New Mexico, Oregon, Rhode Island, Vermont, Washington, and the District of Columbia on the Design of a Program to Reduce Carbon Pollution from Existing Power Plants'' (Dec. 16, 2013).

opportunities for re-dispatch.[226] Within the 5-to-15-year planning horizon established in this proposal to begin in June 2015, most of these companies are likely to be investing in new generation and can consider options such as increased reliance on new renewable generating capacity. They also run energy efficiency programs for their customers.

Municipal utilities and rural cooperatives that own generating asset portfolios also have multiple options for reducing CO_2 emissions, particularly generation and transmission cooperatives and larger municipal utilities. They can implement unit-specific improvements, re-dispatch to lower emitting resources, employ energy efficiency and renewable energy strategies, and explore longer-term capacity planning strategies. For cooperatives and municipal utilities with smaller fleets, re-dispatching among their own units may not provide as many opportunities, particularly in the short term. But because of the timing flexibility in the guidelines, these owners can use both short-term dispatch strategies and longer-term capacity planning strategies to reduce GHG emissions, and in many cases financing is available at tax-advantaged or subsidized rates. At the same time, in formulating their plans, states will be in a position to recognize the distinctive attributes of smaller utilities—and, of course, may consider participating in integrated multi-state compliance strategies to increase the flexibility and cost-saving opportunities that would be available to the covered EGUs.

Some stakeholders have expressed concerns that municipal utilities and rural cooperatives can face other challenges as well. According to these stakeholders, in deregulated areas, even though these utilities may be fully vertically integrated entities, they may not have as much flexibility to control dispatch because they are operating in a competitive market, where they can be in a position in which they need to operate if called upon. Even in this case, the timing flexibility of the rule allows them to consider longer-term capacity planning strategies. These can include building or contracting for electric supply from lower-emitting sources, use of distributed renewable technologies, and use of demand-side energy efficiency measures. There are a number of municipal utilities and rural cooperatives that are already aggressively pursuing such strategies.[227] Nevertheless, in recognition of stakeholders' expressed concerns, we invite comment on whether there are special considerations affecting small rural cooperative or municipal utilities that might merit adjustments to this proposal, and if so, possible adjustments that should be considered.

Independent power producers (IPPs) may also face unique challenges but nevertheless have options. Companies with coal-fired EGUs can implement efficiency improvements as well as other unit-level compliance options such as co-firing or fuel switching. While these types of companies do not use the integrated resource planning process that many vertically integrated utilities use, they still undertake long-term business planning and as a result are in a position to consider different long-term strategies related to their generating assets. Many IPPs are actively developing renewable generating capacity and natural gas-fired generating capacity. IPP owners could also fund demand-side energy efficiency programs and document the resulting electricity savings.

(ii) Actions by States

Another reason why the measures in building blocks 2, 3, and 4 are ''adequately demonstrated'' is that states may adopt them and, in fact, many states have already adopted many of them.

For example, several states have already adopted renewable energy (RE) and demand-side energy efficiency (EE) measures in their CAA section 110 state implementation plans (SIPs) for attaining and maintaining the national ambient air quality standards (NAAQS). The EPA has provided initial guidance for states to do so.[228] Some state air agencies did so for their 1997 8-hour ozone NAAQS SIPs that were due in 2007; for example, Washington, DC, included the purchase of wind power and the installation of LED traffic lights [229]; Dallas, Texas included efficiency measures from the Texas Emissions Reduction Program (TERP) [230]; and Connecticut included projects such as high efficiency air conditioners, compact fluorescent lighting, combined heat and power (CHP), and solar photovoltaic installations.[231] Since that time, many states have adopted legislative mandates for energy efficiency or renewable energy, and states have expressed interest in including EE/RE policies and programs in upcoming NAAQS SIPs. The EPA has provided additional guidance [232] and has partnered with the Northeast States for Coordinated Air Use Management (NESCAUM) and three states (Maryland, Massachusetts, and New York) to identify opportunities for including EE/RE in a NAAQS SIP and to provide real-world examples and lessons learned through those states' case studies.[233]

It should be recognized that each state's electric utility sector operates under distinctive conditions and circumstances. The EPA's proposal ensures that states retain flexibility to craft standards of performance that can accommodate characteristics including fuel sources, types of EGU owners within a state (e.g., investor-owned, municipal, and cooperative utilities, and independent power producers), and regulatory structure (e.g., regulated or restructured). States can tailor their regulatory mechanisms to recognize differences, for example by creating budgets on a company-wide basis or using market-based mechanisms such as mass-based trading systems, to ensure that requirements are achievable.

The proposal also recognizes that states have different resource bases and energy policies in place, and these differences are taken into account in the state goal-setting and computation process. For instance, while the EPA's BSER assumptions consider re-dispatch to NGCC units, they do not consider re-dispatch beyond the NGCC capacity already existing in a state. In that way, the proposal does not presume that

[226] *http://online.wsj.com/article/PR-;CO-20140508-;915605.html.*

[227] For examples, see Large Public Power Council, Energy Efficiency Working Group, Second Annual Energy Efficiency Benchmarking Report (2013); *https://www.nreca.coop/nreca-on-the-issues/energy-operations/energy-efficiency/.*

[228] *See, e.g.,* Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures (Aug. 2004), *http://www.epa.gov/ttn/oarpg/t1/memoranda/ereseerem_gd.pdf;* Incorporating Emerging and Voluntary Measures in a State Implementation Plan (SIP) (Sept. 2004), *http://www.epa.gov/ttn/oarpg/t1/memoranda/evm_ievm_g.pdf.*

[229] DC Region 8-hour ozone SIP at 126, *http://www.mwcog.org/uploads/pub-documents/9FhcXg20070525084306.pdf.*

[230] Dallas/Ft. Worth, Texas 8-hour ozone SIP, *http://www.gpo.gov/fdsys/pkg/FR-2008-08-15/pdf/E8-18835.pdf.*

[231] CT 1997 8-hour ozone SIP Web site, *http://www.ct.gov/deep/cwp/view.asp?a=2684&q=385886&depNav_GID=1619* (see Attainment Demonstration TSD, Chapter 8 at 31, *http://www.ct.gov/deep/lib/deep/air/regulations/proposed_and_reports/section_8.pdf*).

[232] Roadmap for Incorporating EE/RE Policies and Programs into SIPs/TIPs (July 2012), *http://epa.gov/airquality/eere/manual.html.*

[233] States' Perspectives on EPA's Roadmap to Incorporate Energy Efficiency/Renewable Energy in NAAQS State Implementation Plans: Three Case Studies, Final Report to the U.S. Environmental Protection Agency (Dec. 2013), *http://www.nescaum.org/documents/nescaum-final-rept-to-epa-ee-in-naaqs-sip-roadmap-case-studies-20140522.pdf.*

states with limited natural gas generation or infrastructure will have to develop those resources.

Furthermore, while the BSER reflects best practices for both renewables and energy efficiency, it also recognizes that some states have made more progress than others in these areas. The BSER allows time for states to ramp up to greater levels of energy efficiency and use and development of renewable energy resources, should they choose those approaches. With respect to renewable energy, the proposal also recognizes that different areas of the country have different resource bases and does not presume that a uniform level of penetration of renewable generation is appropriate for every state.

The features provided in this proposal to ensure policy flexibility can be used by all states to address their unique circumstances. In a regulated state, if a company's compliance strategies included reducing generation at higher-emitting EGUs, it would work through its state's integrated planning process to ensure that adequate generation was available through a combination of all four building blocks. Cost recovery, and cost oversight, can be achieved through rate cases before state regulators. In a restructured state, even if affected companies responded to the guidelines by reducing generation without themselves replacing that generation, the electricity markets that have developed would react to ensure the availability of replacement generation. Other companies would see opportunities to build or ramp up existing lower-emitting generation, and in some markets that treat demand-side resources on par with supply side resources, energy service companies would likely see opportunities. Further, state regulators can continue to play an important role in restructured states as well, authorizing or reviewing both renewable energy procurement and demand-side energy efficiency programs. In all types of market structures, large energy users might independently see additional energy efficiency opportunities or opportunities for self-generation using options such as combined heat and power, solar, or power purchase agreements, and states can structure their plans to allow the CO_2 reductions achieved at affected EGUs through such actions to assist in reaching compliance. As discussed in earlier portions of this section and elsewhere in the preamble, each of the building blocks is already being widely implemented, is consistent with industry trends, and consists of CO_2 reduction methods already widely accepted in the eyes of various stakeholders, as was clear from views expressed in our outreach process.

Moreover, there are mechanisms through which states could require measures from any of the building blocks in state plans. In fact, the state plan formulation process through which CAA section 111(d) is implemented reinforces the determination that these measures are components of the BSER. For example, states would have authority to impose measures such as best practices for operation and maintenance of EGUs, dispatch limits, renewable energy resource requirements, and demand-side energy efficiency requirements. States also would have authority to establish requirements that change the relative costs of generation from more carbon-intensive and less carbon-intensive EGUs, for example by creating emission allowance systems that cause market participants and system operators to take account of CO_2 emission rates as an element of variable operating costs. Such an approach can encourage measures from all of the building blocks simultaneously. As noted elsewhere in the preamble, many states have already pursued one or more of these approaches.[234]

It also should be noted that during the public outreach sessions, stakeholders generally recommended that state plans be authorized to rely on, and that affected sources be authorized to implement, re-dispatch, renewable energy measures, and demand-side energy efficiency measures in order to meet states' and sources' emission reduction obligations. The EPA agrees that state plans may include these measures, at least under certain circumstances, as discussed in Section VIII, and that sources may rely on them to achieve required reductions. It is clear that these types of measures are well-accepted by the stakeholders as means to reduce emissions from affected sources. The fact that state plans and sources would be expected to use these types of measures to reduce emissions supports the view that these measures are part of a ''system of emission reduction'' for those sources that the EPA may evaluate against the appropriate criteria to determine whether they comprise the ''best system of emission reduction . . . adequately demonstrated.''

(iii) Regional Organizations

Another reason why the measures in building blocks 2, 3, and 4 are ''adequately demonstrated'' is that they can be accommodated through the existing regional components of the electricity system.

On the regional level, ISO/RTOs control dispatch and are responsible for reliable operation of the bulk power system.[235] They can seek solutions, such as capacity markets and transmission upgrades, to preserve resource adequacy and ensure the continued reliable operation of the grid. For this proposal, the ISO/RTO Council has already submitted a set of recommendations they believe can help balance the needs of lower emissions, economic dispatch, and reliability, which is discussed in greater detail in Section VIII.F.7 of this proposal.[236] For areas of the country that are not covered by an ISO/RTO, there are regional groups, such as ColumbiaGrid, Northern Tier Transmission Group and WestConnect in the west, and system operators such as Southern Company in the southeast, that can provide these functions. In shifting to lower-emitting units, grid operators across the country factor environmental costs into their economic dispatch through a variety of mechanisms, including allowance costs, variable costs associated with operating environmental controls, and operating limits for high-emitting units.

(iv) Concerns From Stakeholders; Solicitation of Comment

We note that some stakeholders have argued that CAA section 111(a)(1) does not authorize the EPA to identify re-dispatch, low- or zero-emitting generation, or demand-side energy efficiency measures (building blocks 2, 3, and 4) as components of the ''best system of emission reduction . . . adequately demonstrated.'' According to these stakeholders, as a legal matter, the BSER is limited to measures that may be undertaken at the affected units, and not measures that are beyond the affected units; the measures in building blocks 2, 3, and 4 are ''beyond-the-unit'' or ''beyond-the-fenceline'' measures because they are implemented outside of the affected units and outside their control; and as a result, those measures cannot be considered components of the BSER.

We welcome comment on this issue. As discussed above, we propose that the

[234] See the discussions of California California Global Warming Solutions Act and RGGI above in this section and elsewhere in the preamble.

[235] Across all markets, at the federal level, FERC and NERC create and oversee standards for reliability. NERC works with electric reliability councils and control areas that comprise all types of utilities and system operators to ensure that adequate generation is available.

[236] *http://www.isorto.org/Documents/Report/20140128_IRCProposal-ReliabilitySafetyValve-RegionalComplianceMeasurement_EPA-C02Rule.pdf.*

provisions of CAA section 111 do not by their terms preclude the BSER from including those types of measures. In addition, as noted above, under our proposed approach, affected sources may themselves implement the measures included in building blocks 2, 3, and 4, so that those measures are within their control with the result of their application being emissions reductions at affected EGUs. Moreover, under our alternative approach, the ''system of emission reduction'' includes reductions in utilization at the affected sources themselves.[237] It should also be noted that, as discussed above, the re-dispatch measures in building block 2 are limited to affected sources. Thus, the proposed approach and alternative described above respond to these stakeholder concerns.

7. Alternate Approach to the Best System of Emission Reduction

As an alternative to the approach described above for determining the ''best system of emission reduction . . . adequately demonstrated,'' the ''system of emission reduction'' may be identified as including, in addition to building block 1, the reduction of affected fossil fuel-fired EGUs' mass emissions achievable through reductions in generation of specified amounts from those EGUs. Under this approach, the measures in building blocks 2, 3, and 4 would not be components of the system of emission reduction but instead would serve as bases for quantifying the reduced generation (and therefore emissions) at affected EGUs, and assuring that the amount of reduced generation meets the criteria for the ''best'' system that is ''adequately demonstrated'' because, among other things, the reduced generation can be achieved while the demand for electricity services can continue to be met in a reliable and affordable manner. Specifically, the amount of generation from the increased utilization of NGCC units would determine a portion of the amount of the generation reduction component of the BSER for affected fossil fuel-fired steam EGUs, and the amount of generation from the use of expanded low- and zero-carbon generating capacity that could be provided, along with the amount of generation from fossil fuel-fired EGUs that could be avoided through the promotion of demand-side energy efficiency, would determine a portion of the amount of the generation reduction component of the BSER for all affected EGUs.

Reduced generation is encompassed by the terms of the phrase ''system of emission reduction'' in CAA section 111(a)(1), as a matter of *Chevron* step 1, because, in accordance with the above-discussed definition of ''system,'' reduced generation is a ''set of things''—which include reduced use of generating equipment and therefore reduced fuel input—that the affected source may take to reduce its CO_2 emissions.[238] If that phrase is not considered clear by its terms, then, under *Chevron* step 2, it may reasonably be interpreted to include reduced generation.[239] As discussed in the Legal Memorandum, the legislative history of the 1970 CAA Amendments indicates that Congress recognized that emitting sources could comply with pollution control requirements by reducing production, including retiring.[240] As also noted in the Legal Memorandum, examples of reduced utilization as a means of reducing emissions are found in settlement agreements between the EPA and fossil fuel-fired EGUs to resolve alleged violations of the CAA new source review (NSR) requirements.[241]

Reduction of, or limitation on, the amount of generation is already a well-established means of reducing emissions of pollutants in the electric sector, notwithstanding the fact that as a practical matter, some facilities may have to operate, or remain available, to ensure system reliability. For example, reduced generation by higher-emitting sources is one of the compliance options available to, and used by, EGUs to comply with the Clean Air Act acid rain program in CAA title IV, as well as the transport rules that we refer to as the NO_X SIP Call[242] and the Clean Air Interstate Rule (CAIR).[243] Reduction in generation is also a possible means by which an EGU can achieve compliance with its requirements under RGGI.

Reduced generation in specified amounts is part of the ''best'' system of emission reduction that is ''adequately demonstrated.'' Reduced generation is technically feasible because of a source's ability to limit its own operations. In addition, the amounts of generation and emission reductions may be determined with precision through the application of building block 2, 3, and 4 measures for increased generation from low- or zero-emitting sources and increased demand-side energy efficiency, which, in turn, ensure the reliability of the electricity grid and the affordability of electricity to businesses and consumers.

Because of the availability of the measures in building blocks 2, 3, and 4, the proposed levels of reduced generation are of reasonable cost for the affected source category and the nationwide electricity system, do not jeopardize reliability, result in an important amount of emission reductions, are consistent with current trends in the electricity sector, and promote the development and implementation of technology that is important for continued emissions reductions. All these results come about because the operation of the electrical

[237] Commenters have critiqued this ''at-the-unit'' and ''beyond-the-unit'' distinction as follows:

There is an argument that the at-the-unit/beyond-the-unit distinction is not a meaningful one. Specifically, it could be argued that the distinction between at-the-unit and beyond-the-unit measures is largely artificial, because all of the emission reductions under consideration—whether from at-the-unit measures (e.g., fuel-switching or efficiency upgrades) or from beyond-the-unit measures—are, in fact, emission reductions at or from electric generating units on the interconnected electric grid. For example, neither the addition of renewable generation nor the reduction of end-user demand directly reduces atmospheric emission of CO_2; rather these measures permit fossil EGUs to reduce their own output and emissions. It can be argued that all of the systems of emission reduction here contemplated—whether they involve end-use energy efficiency, displacing high-emission generation with lower emission generation, fuel-switching, heat-rate improvements, etc.—are effectively at-the-unit measures that ultimately reduce emissions solely from regulated EGUs. If energy-efficiency programs, added renewable energy, and redispatch from higher emitting facilities to lower emitting facilities are viewed as at-the-unit systems of emission reduction, the at-the-unit/beyond-the-unit distinction arguably becomes irrelevant—at least from a legal perspective. Rather, the real issue may come down to whether § 111(d) authorizes the EPA to require EGUs to curtail their output of electricity as a means of complying with the rule.

Nordhaus R., Gutherz I., ''Regulation of CO_2 Emissions from Existing Power Plants Under § 111(d) of the Clean Air Act: Program Design and Statutory Authority,'' *Environmental Law Reporter,* 44: 10366, 10383 n. 133 (May 2014).

[238] For this reason, under a *Chevron* step 1 interpretation, ''system of emission reduction'' includes reduced generation.

[239] For these reasons, under a *Chevron* step 2 interpretation, ''system of emission reduction'' includes reduced generation.

[240] *See* CAA section 110(g) (authorizing temporary emergency suspensions of SIP revisions if needed to prevent the closing of a source of air pollution), enacted as CAA section 110(f) in the 1970 CAA Amendments; 116 Cong. Rec. 42384 (Dec. 18, 1970), *reprinted in* Congressional Research Service, *A Legislative History of the Clean Air Act Amendments of 1970,* vol. 1, at 132–33 (1974) (statement of Sen. Muskie) (discussing criteria for sources to receive compliance date extensions). Sen. Muskie added that the emission standards set by the EPA for hazardous air pollutants ''could include emission standards which allowed for no measureable emissions,'' *id.,* which further suggests that, as a practical matter, the standards could result in reduced production.

[241] *See, e.g.,* Consent Decree at 18, *United States* v. *Wis. Power & Light Co.,* No. 13–cv–266 (W.D. Wis. filed Apr. 22, 2013), *available at http://www2.epa.gov/sites/production/files/documents/wisconsinpower-cd.pdf.*

[242] 63 FR 57356 (Oct. 27, 1998).

[243] 70 FR 25162 (May 12, 2005).

grid through integrated generation, transmission, and distribution networks creates fungibility for electricity and electricity services, which allows decreases in generation at affected fossil fuel-fired steam EGUs to be replaced by increases in generation at affected NGCC units (building block 2) and allows decreases in generation at all affected EGUs to be replaced by increased generation at low- or zero-carbon EGUs (building block 3) or by decreased demand (building block 4). Further, this fungibility increases over longer timeframes with the opportunity to invest in infrastructure improvements, and as noted elsewhere, this proposal provides an extended state plan and source compliance horizon. These characteristics of the integrated electricity system assure that reduced generation in specified amounts meets the criteria to qualify as part of the ''best'' system of emission reduction.

Reduced generation in those amounts is also ''adequately demonstrated.'' As noted above, the measures in building blocks 2, 3, and 4 are already in widespread use in the industry. At the levels proposed, they have the technical capability to substitute for reduced generation at some or all affected EGUs at reasonable cost. The NGCC capacity necessary to accomplish the levels of generation reduction proposed for building block 2 is already in operation or under construction. Moreover, it is reasonable to expect that the incremental resources reflected in building blocks 3 and 4 will develop at the levels requisite to ensure an adequate and reliable supply of electricity at the same time that affected EGUs may choose or be required to reduce their CO_2 emissions by means of reducing their utilization. There are several reasons for this. First, the affected sources themselves could invest in new renewable energy resources and demand-side energy efficiency, as discussed above.[244] Second, the states, as part of their plans, have mechanisms available to put these substitutes in place: They could establish requirements or incentives that would result in new renewable energy and demand-side energy efficiency programs, as also discussed above.[245] Third, as also discussed above, regional entities in the electricity system can accommodate these substitutes.

Most broadly, with respect to the measures in building blocks 2, 3, and 4, provided there is sufficient lead time for planning, mechanisms are in place in both regulated and deregulated electricity markets to assure that substitute generation will become available and/or steps to reduce demand will be taken to compensate for reduced generation by affected EGUs. These mechanisms are based on, among other things, the integrated nature of the electricity system coupled with the availability of capacity in existing NGCC units, the growing institutional capacity of entities that develop renewable energy and demand-side energy efficiency resources, and the ability of system operators and state regulators to incentivize further development of those resources.

The EPA solicits comment on whether measures in addition to those in building blocks 2, 3, and 4 could support the showing that reduced utilization is ''adequately demonstrated,'' including additional NGCC capacity that may be built in the future, as discussed in Section VI.C.5.c above.

8. The EPA's Discretion in Applying the Criteria for the Best System of Emission Reduction

As discussed above, each of the approaches to determining the ''best system of emission reduction . . . adequately demonstrated'' entails applying the criteria described in the D.C. Circuit case law for evaluating the BSER. It should be emphasized that under the case law, the EPA has significant discretion in weighing the different criteria, and may weigh them differently in different rulemakings.

For the present proposal, the EPA is heavily weighting three criteria in particular: The amount of emission reductions, the cost of achieving those reductions, and the promotion of technology implementation—while also noting that the proposed BSER determination readily meets the other criteria as well. The EPA considers it especially important in this rulemaking, while ensuring that electricity system reliability is preserved and that costs are not unreasonable, to achieve a significant amount of emissions reductions in response to the urgency and the magnitude of the need to mitigate climate change. The EPA discusses this above in the sections concerning the scientific background for this rulemaking. The EPA also considers it especially important for the present proposal that the overall costs of achieving the emission reductions should be reasonable. Costs can be minimized through the flexibility to choose from a broad range of CO_2 emission reduction measures, as is provided in the portion of this proposal addressing state plans, and a similarly broad range of emission reduction measures, represented by the four building blocks discussed above, should serve as the basis supporting the BSER. Finally, the EPA also considers it especially important for the present proposal to promote technological innovation and development of, in particular, the measures in building blocks 3 and 4 (to reiterate, low- or zero-carbon electricity generation and demand-side energy efficiency, respectively). Promoting innovation in, and market penetration of, these technologies and practices is critical to making the substantial reductions in emissions that will be required during the next few decades to reduce the risks to public health and welfare and our economic well-being of dangerous climate change.

In addition, in this rulemaking, the EPA is determining the BSER in a manner that is consistent with, and that provides further impetus for, current trends in the nation's electricity system that offer promise to reduce the carbon intensity of the system over the near- and long-term, while maintaining reliability and affordability. This approach is consistent with the case law, which authorizes the EPA to determine BSER by ''balanc[ing] long-term national and regional impacts,'' and by ''using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems. . . .''[246]

9. State-Wide Application of the BSER; Appropriateness of Standards of Performance

An important aspect of the BSER for affected EGUs is that the EPA is proposing to apply it on a statewide basis. The statewide approach also underlies the required emission performance level, which is based on the application of the BSER to a state's affected EGUs, and which the suite of measures in the state plan, including the emission standards for the affected

[244] It should be noted that in light of the low current and projected near term prices for natural gas, market forces may lead investors to choose to build new NGCC units, rather than new renewable resources. This result would not call into question the technical feasibility of a BSER that included reductions in fossil fuel-fired generation by the amount of a specified amount of new renewable resources. This is because under these circumstances, the fossil fuel-fired generators could still reduce their generation without causing reliability or other problems in the electric power system.

[245] The nuclear generating capacity reflected in building block 3 is already in operation or under construction.

[246] *Sierra Club* v. *Costle,* 657 F.2d 298, 331 (D.C. Cir. 1981).

EGUs, must achieve overall. The state has flexibility in assigning the emission performance obligations to its affected EGUs, in the form of standards of performance—and, for the portfolio approach, in imposing requirements on other entities—as long as, again, the required emission performance level is met.

This state-wide approach both harnesses the efficiencies of emission reduction opportunities in the interconnected electricity system and is fully consistent with the principles of federalism that underlie the Clean Air Act generally and CAA section 111(d) particularly. That is, this provision achieves the emission performance requirements through the vehicle of a state plan, and provides each state significant flexibility to take local circumstances and state policy goals into account in determining how to reduce emissions from its affected sources, as long as the plan meets minimum federal requirements.

In this subsection, we describe how this approach, and the standards of performance for the affected EGUs that the states will establish through the process we describe, are consistent with the CAA section 111(d)(1) and (a)(1) provisions.

For convenience, we set out the requirements of CAA section 111(d)(1) and (a)(1) here: Under CAA section 111(d)(1), the state must adopt a plan that ''establishes standards of performance for any existing source.'' Under CAA section 111(a)(1), a ''standard of performance'' is a ''standard for emissions . . . which reflects the degree of emission limitation achievable through the application of the best system of emission reduction . . . adequately demonstrated.'' The EPA proposes to interpret these provisions as set forth in this sub-section.

The first step is for the EPA to determine the ''best system of emission reduction . . . adequately demonstrated.'' As discussed at length elsewhere, the EPA is proposing two alternative BSER. The first is the measures in building blocks 1 through 4 combined. This includes operational improvements and equipment upgrades that the coal-fired steam EGUs in the state may undertake to improve their heat rate by, on average, six percent and increases in, or retention of, zero- or low-emitting generation, as well as measures to reduce demand for generation, all of which, taken together, displace, or avoid the need for, generation from the affected EGUs. This BSER is a set of measures that impacts affected EGUs as a group. The alternative approach to BSER is building block 1 combined with reduced utilization from the affected EGUs in the state as a group, in the amounts that can be replaced by an increase in, or retention of, zero- or low-emitting generation, as well as reduced demand for generation.

After determining the BSER, the EPA then applies the BSER to each state's affected EGUs, on a state-wide basis. Building block 1 is applied to the coal-fired steam EGUs on a statewide basis; building block 2 is applied to increase the generation of the NGCC units in the state up to certain amounts, and decrease the amount of generation from steam EGUs accordingly; and the measures in building blocks 3 and 4 are applied to reduce, or avoid, generation from all affected EGUs on a state-wide basis. Under the alternative formulation of the BSER, the total amount of reduced generation from the affected EGUs in the state, associated with the measures in building blocks 2, 3, and 4, is determined on the basis of each state's affected EGUs as a group.

This statewide approach to applying the BSER is consistent with the CAA section 111(a)(1) definition of ''standard of performance,'' which, as quoted above, refers to ''the application of the [BSER],'' for the purpose of determining ''the degree of emission limitation achievable,'' but does not otherwise constrain how the BSER is to be applied.

As a result, the EPA may apply the BSER to all of the affected EGUs in the state as a group. Similarly, the implementing regulations give the EPA broad discretion to identify the group of sources to which the BSER is applied. The regulations provide that the EPA ''will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.'' Applying the BSER to the affected EGUs in each state as a group is appropriate, and therefore is consistent with these regulations.

As part of applying the BSER, the EPA, to return to provisions of CAA section 111(a)(1), calculates the ''emission limitation achievable through the application of the [BSER].'' In this rulemaking, we refer to this amount as the state goal. As noted, the EPA expresses the state goal in the emission guidelines as an emission rate.

The state must develop a state plan that achieves the state goal, either in the form of an emission rate, as specified for the state in the emission guidelines, or a translated mass-based version of the rate-based goal. We refer to the state goal, in the form used by the state as the foundation of its plan, as the required emission performance level.

As part of its state plan, the state must establish ''standards of performance'' for its affected EGUs. To do so, the state may consider the measures the EPA identified as part of the BSER or other measures that reduce emissions from the affected EGUs. Moreover, the state has the flexibility to establish emission standards in the degree of stringency that the state considers appropriate. The primary limitation on the state's flexibility is that the emission standards applied to all of the state's affected EGUs—and, in the case of states that adopt the portfolio approach, the requirements imposed on other affected entities—taken as a whole, must be demonstrated to achieve the required emission performance level. In addition, the state may make the emission standards for any of its affected EGUs sufficiently stringent, so that the standards and any requirements imposed on other affected entities (if relevant), taken as a whole, achieve a level of emission performance that is better than the required emission performance level. *See* CAA section 116, 40 CFR 60.24(g).

Under these circumstances—that the emission standards that the state establishes for its affected EGUs and any other requirements for the other affected entities, as relevant, taken together, are at least as stringent as necessary to achieve the required emission performance level for the state's affected EGUs—each emission standard that the state adopts for each of its affected EGUs will meet the definition of a ''standard of performance'' under CAA section 111(a)(1). Specifically, the ''standard of performance'' for each source will constitute, to return to the provisions of CAA section 111(a)(1), ''a standard for emissions which reflects [that is, embodies, or represents] [247] the degree [that is, the portion] of emission limitation achievable through the application of the [BSER]'' [that is, as noted above, the required emission performance level for all affected sources in a state]. That ''degree'' or portion of the required emission performance level is, in effect, the portion of the state's obligation to limit its affected sources' emissions that the state has assigned to each particular affected source. An emission standard

[247] *See* Oxford Dictionary of English (3rd ed. 2010 (online version 2013)) (defining ''reflect'' as, among other things, ''embody or represent (something) in a faithful or appropriate way'').

meets this definition of the term ''standard of performance'' regardless of whether it is part of a plan that adopts the portfolio approach (in which case, the standard will reflect a relatively smaller part of the emission performance level) or one that imposes the plan's emission limitation obligations entirely on the affected EGUs (in which case, the standard will reflect a relatively larger part of the emission performance level).

These proposed interpretations of the provisions of CAA sections 111(d)(1) and (a)(1) are fully consistent with the EPA's overall approach in this rulemaking to determining and applying the BSER and identifying the appropriate level of emission performance for the affected EGUs. As noted, this approach entails applying the BSER on a state-wide basis and, based on the BSER, identifying the emission performance level for each state's affected EGUs that each state must achieve, so that each state may then assign the emission limitation obligations among its sources. As noted, this approach is fully consistent with the interconnected nature of the electricity system and with the principles of federalism that underlie CAA section 111(d).

It should be emphasized that each state has many options for assigning the emission limitation obligations among its affected sources. For example, the state could impose emission standards that are consistent with the BSER. Under these circumstances, the state may assign to different affected sources emission standards with different levels of stringency because the state will have determined that those standards are consistent with the nature of each source's participation in the state's electricity system. In addition, the state could authorize emission trading as part of the emission standards for affected sources. Under these circumstances, if an affected source's emission level was higher than the standard the state established for it, the source could achieve the standard by purchasing additional emission rights through the trading program.

Finally, it should be noted that states retain authority under CAA section 116 and 40 CFR 60.24(g) to impose standards of performance that, cumulatively, are more stringent than the emission performance level.[248]

10. Combined Categories

As discussed above, the EPA is soliciting comment on combining the category of steam EGUs and the category of combustion turbines (which include NGCC units) into a single category for fossil fuel-fired EGUs, for purposes of promulgating emission guidelines for CO_2 emissions. The EPA solicits comment on whether combining the categories is, as a legal matter, a prerequisite for (i) identifying as a component of the BSER re-dispatch between sources in the two categories (i.e., re-dispatch between steam EGUs and NGCC units), or (ii) facilitating averaging or trading systems that include sources in both categories, which states may wish to adopt.

11. Severability

We consider our proposed findings of the BSER with respect to the various building blocks to be severable, such that in the event a court were to invalidate our finding with respect to any particular building block, we would find that the BSER consists of the remaining building blocks. The state goals that would result from any combination of the building blocks can be computed from data included in the Goal Computation TSD and its appendices using the methodology described in the preamble and that TSD.

12. Solicitation of Comment

We invite comment on all aspects of our proposed interpretation and alternate interpretation of the BSER for CO_2 emissions from existing fossil fuel-fired EGUs, both as identified above and as further discussed in the Legal Memorandum in the docket.[249] In particular, we invite comment on our analysis of the four building blocks as components of the BSER, whether any other potential measures should be considered, our analysis of the combinations of building blocks 1 and 2 and of all four building blocks, and the legal, technical, and economic bases of our conclusions. With regard to comments received during the stakeholder meetings, some commenters noted that trading programs like RGGI have been successful at reducing GHGs, and other commenters provided specific BSER proposals based on trading and/or emissions averaging approaches. We specifically request comment on whether any of these approaches should be considered as the BSER. We also specifically invite comment on the question, raised by some stakeholders, as to whether if measures may be relied on in the state plan to achieve emissions reductions, they cannot be excluded from the scope of the BSER solely because they involve actions by entities or at locations other than affected sources.

VII. State Goals

A. Overview

In this section, the EPA sets out proposed state-specific CO_2 emission performance goals to guide states in development of their state plans. The proposed goals reflect the EPA's quantification of each state's average emission rate from affected EGUs that could be achieved by 2030 and sustained thereafter, with interim goals that would apply over a 2020–2029 phase-in period, through reasonable implementation, considering the unique circumstances of each individual state, of the best system of emission reduction adequately demonstrated (based on all four building blocks) described above. In addition, we are taking comment on a second set of state-specific goals that would reflect less stringent application of the same BSER, in this case by 2025, with interim goals that would apply over a 2020–2024 phase-in period. As promulgated in the final rule following consideration of comments received, the interim and final goals will be binding emission guidelines for state plans.

The proposed goals are expressed in the form of state-specific, adjusted[250] output-weighted-average CO_2 emission rates for affected EGUs. However, states are authorized to translate the form of the goal to a mass-based form, as long as the translated goal achieves the same degree of emission limitation.[251]

The EPA is also proposing that measures taken by a state or its sources

[248] The EPA's approach may also be characterized as (i) determining the BSER for the affected EGUs, (ii) establishing as the emission guideline the standard for emissions that the affected EGUs in the state can achieve on average through the application of the BSER, and (iii) as part of the emission guideline, authorizing each state to establish as the applicable standard for each affected EGU, the standard that the state considers appropriate and that when totaled with the standards established for the other EGUs (and as may be adjusted to account for the portfolio approach, if that approach is adopted by the state) is at least as stringent as the average standard in the emission guideline. As noted in the accompanying text, a state has many ways to establish standards that meet the CAA requirements, including, for example, following the BSER or authorizing emission rate averaging or trading.

[249] However, as noted, we are not soliciting comment on issues that were resolved by the implementing regulations.

[250] As described below, the emission rate goals include adjustments to incorporate the potential effects of emission reduction measures that address power sector CO_2 emissions primarily by reducing the amount of electricity produced at a state's affected EGUs (associated with, for example, increasing the amount of new low- or zero-carbon generating capacity or increasing demand-side energy efficiency) rather than by reducing their CO_2 emission rates per unit of energy output produced.

[251] A method for translating from a rate-based goal to a mass-based goal is discussed in the Projecting CO_2 Emission Performance in State Plans TSD.

after the date of this proposal, or programs already in place, and which result in CO_2 emission reductions at affected EGUs during the 2020–2030 period, would apply toward achievement of the state's CO_2 goal. Thus, states with currently existing programs and policies, and states that put in place new programs and policies early, will be better positioned to achieve the goals.

The EPA is proposing to finalize the goal for each state as proposed, and adjusted as may be appropriate based on comments. A state may demonstrate during the comment period that application of one of the building blocks to that state would not be expected to produce the level of emission reduction quantified by the EPA because implementation of the building block at the levels envisioned by the EPA was technically infeasible, or because the costs of doing so were significantly higher than projected by the EPA. While the EPA would consider this in setting final state goals, the EPA would also consider (and would expect commenters to address) whether a similar overall state goal could still be achieved through more aggressive implementation of one or more of the measures encompassed in the other building blocks or through other, comparable measures. For example, if a state demonstrates during the public comment period that the state's coal-fired steam EGUs could only achieve an average four percent heat rate improvement, instead of the six percent that the EPA is proposing to determine is achievable from application of building block 1, the EPA would not adjust the state's goal to reflect that change unless the state also demonstrates that it could not get additional reductions from application of building blocks 2, 3 or 4, or in related, comparable measures.

Each of the building blocks establishes a reasonable level of reductions, but not necessarily the maximum amount that could be achieved if that building block, and no other, were the basis supporting the BSER. Together the building blocks establish a reasonable overall level of reductions and effort that the EPA considers appropriate at this time. This amount of emission reductions is significant and will require effort and adjustments throughout the electricity sector. In light of the overall effort to achieve the state goals based on a combination of all four building blocks at the levels specified, the EPA is not proposing a higher level of reductions at this time, even though the measures in the building blocks could be implemented more stringently to achieve greater emission reductions.

Because the building blocks each establish a reasonable level of emission reduction rather than the maximum possible level of reduction, the EPA expects that, for any particular state, even if the application of the measures in one building block to that state would not produce the level of emission reductions reflected in the EPA's quantification for that state, the state will be able to reasonably implement measures in other of the building blocks more stringently, so that the state would still be able to achieve the proposed goal. Accordingly, the EPA proposes that even if a state demonstrates during the comment period that application of a building block to that state would not result in the level of emission reductions reflected in the EPA's quantification for that state, then the state should also explain why the application of the other building blocks would not result in greater emission reductions than are reflected in the EPA's quantification for that state. In light of the fact that the building blocks are based on a reasonable level of stringency and not the most stringent possible level, the EPA expects that such offsetting emission reductions at the state's affected EGUs from the application of other building blocks will be available, so that the EPA will be able to finalize the state goals as proposed. For example, a state's inability to meet the level of emission reductions anticipated through use of one building block may free up resources that the state could then devote to more stringent implementation of another building block. This approach would mean that overall, the same nationwide level of emission reductions as proposed would be achieved. The EPA invites comment on this aspect of the proposal.

At this time, the EPA is not proposing CO_2 emission performance goals for either Indian country or U.S. territories. The EPA does plan to establish CO_2 emission goals for both Indian country and territories in the future. The EPA plans to conduct additional outreach before setting these goals.

Issues related to the establishment of CO_2 goals and CAA section 111(d) plans for Indian country are discussed in Section V.D of this preamble. As noted in that discussion, the EPA is aware of four potentially affected power plants located in Indian country: The South Point Energy Center, on Fort Mojave tribal lands within Arizona; the Navajo Generating Station, on Navajo tribal lands within Arizona; the Four Corners Power Plant, on Navajo tribal lands within New Mexico; and the Bonanza Power Plant, on Ute tribal lands within Utah.[252] Data for these four power plants have been excluded from the data used to compute the proposed state goals for Arizona, New Mexico, and Utah discussed below.

With respect to territories, the EPA is currently aware of potentially affected EGUs in Puerto Rico, the U.S. Virgin Islands, and Guam. The EPA requests comment on how the BSER would apply to these territories, as well as to American Samoa or the Northern Mariana Islands if potentially affected EGUs are subsequently identified in those territories. In particular, the EPA solicits comment on appropriate alternatives for territories that do not have access to natural gas.[253] Because the data sources we have used for purposes of establishing renewable energy and demand-side energy efficiency targets for states do not cover all the territories, we also solicit comment on ways to determine appropriate renewable energy and demand-side energy efficiency targets using other data sources.

The remainder of this section addresses five sets of topics. First, we discuss several issues related to the form of the goals. Second, we describe the proposed state goals and the computation procedure. Third, we discuss several types of state flexibility with respect to the goals. Fourth, we describe the alternate set of goals offered for comment and certain other approaches we considered. Finally, we discuss the proposal's compatibility with the need to ensure a reliable, affordable supply of electricity.

Some of the topics addressed in this section are addressed in greater detail in supplemental documents available in the docket for this rulemaking, including the Goal Computation TSD and the Greenhouse Gas Abatement Measures TSD. Specific topics addressed in the various TSDs are noted throughout the discussion below.

B. Form of Goals

The proposed goals are presented in the form of adjusted output-weighted-average CO_2 emission rates that the affected fossil fuel-fired EGUs located in each state could achieve, on average, through application of the measures

[252] The South Point facility is an NGCC power plant, and the Navajo, Four Corners, and Bonanza facilities are coal-fired power plants.

[253] As noted in Section VI.C.5.d above, we are requesting comment on whether heat rate improvements for non-coal fossil fuel-fired EGUs should be part of the basis supporting the BSER, with particular reference to the situation of geographically isolated jurisdictions such as the U.S. territories.

comprising the BSER (or alternative control methods). Several aspects of this proposed form of goal are worth noting at the outset: The use of an emission rate-based form (e.g., the quantity of CO_2 per MWh of electricity generated), with the opportunity for the state to adopt a mass-based form (e.g., a cap on the tonnage of CO_2 emissions); the use of output-weighted-average emission rates for all affected EGUs in a state rather than nationally uniform emission rates for all affected EGUs of particular types; the use of adjustments to accommodate measures that reduce CO_2 emissions by reducing the quantity of fossil fuel-fired generation rather than by reducing the CO_2 emission rate per MWh generated by affected sources; the use of emission rates expressed in terms of net rather than gross energy output; and the adjustability of the goals based on the severability of the underlying building blocks.

First, the EPA proposes to use an emission rate-based form for the state-specific goals included in the guidelines, and to give each state the opportunity to translate its rate-based goal to an equivalent mass-based form for state plan purposes. Each of the two forms of goals presents advantages, and states have expressed support for having the flexibility to use either form. Defining emission performance levels in a rate-based form provides flexibility to accommodate changes in the overall quantities of electricity generated in response to increases in electricity demand. Defining emission performance levels in a mass-based form provides relative certainty as to the absolute emission levels that would be achieved as well as relative simplicity in accommodating and accounting for the emission impacts of a wide variety of emission reduction strategies. In light of these respective advantages, we propose to set an emission rate-based form of goal, and to allow any state to translate the rate-based goal to an equivalent mass-based emission performance level for state plan purposes. This approach allows each state to maximize the advantages it considers optimal and is consistent with the state flexibility principle that is central to the EPA's development of this program.

The second aspect noted above concerns the proposed choice of state-specific output-weighted-average emission rates for all affected EGUs in each state rather than nationally uniform emission rates for particular types of affected EGUs. Here, the EPA's main consideration has been to ensure that the proposed goals reflect opportunities to manage CO_2 emissions by shifting generation among different types of affected EGUs. Specifically, because CO_2 emission rates differ widely across the fleet of affected EGUs, and because transmission interconnections typically provide system operators with choices as to which EGU should be called upon to produce the next MWh of generation needed to meet demand, opportunities exist to manage utilization of high carbon-intensity EGUs based on the availability of less carbon-intensive generating capacity. For states and generators, this means that CO_2 emission reductions can be achieved by shifting generation from EGUs with higher CO_2 emission rates, such as coal-fired EGUs, to EGUs with lower CO_2 emission rates, such as NGCC units. Our analysis indicates that shifting generation among EGUs offers opportunities to achieve large amounts of CO_2 emission reductions at reasonable costs. These opportunities can be reflected in a goal established in the form of an output-weighted-average emission rate for multiple affected EGU types. Our approach is also consistent with the fact that the proportions of different EGU types and hence the magnitudes of the generation-shifting opportunities vary across states, and that CAA section 111(d) calls for standards of performance to be established in state plans rather than on a nationwide basis.

The third aspect noted above regarding the proposed form of the goals concerns the adjustments made to the output-weighted-average emission rates in order to accommodate reduced utilization of affected EGUs associated with measures such as increases in low- and zero-carbon generating capacity and demand-side energy efficiency. We recognize that these measures support reduced overall CO_2 mass emissions from affected EGUs through reductions in the quantity of generation from affected EGUs, and not necessarily through reductions in the weighted-average CO_2 emission rates of affected EGUs. Accordingly, we have constructed the emission rate goals in a manner that is intended to account for these generation quantity-reducing measures by making adjustments to the values used in the emission rate computations. The specific adjustments are summarized below in the context of the goal computation methodology and are described in greater detail in the Goal Computation TSD. As described below in Section VIII on state plans, we are proposing that a state choosing a rate-based form of goal would be able to make analogous adjustments when assessing monitored emission performance so that measures that support avoided generation at affected EGUs could be used to help the state meet the rate-based emission performance level reflected in its plan. We note that adjustments of this nature are not necessary when a plan's emission performance level is based on the mass of CO_2 emissions [254] rather than on CO_2 emission rates, because the emission-reducing effects of reduced generation at affected EGUs are evident in the EGUs' reported CO_2 mass emissions.

The fourth aspect noted above concerns the proposed expression of the goals in terms of net energy output [255]—that is, energy output encompassing net MWh of generation measured at the point of delivery to the transmission grid rather than gross MWh of generation measured at the EGU's generator.[256] The difference between net and gross generation is the electricity used at a plant to operate auxiliary equipment such as fans, pumps, motors, and pollution control devices. Because improvements in the efficiency of these devices represent opportunities to reduce carbon intensity at existing affected EGUs that would not be captured in measurements of emissions per gross MWh, we are proposing goals expressed in terms of net generation. Nearly all EGUs already have in place the equipment necessary to determine and report hourly net generation, and we believe that the proposed reporting requirement would therefore not be burdensome. However, we also recognize that at present EGUs report gross rather than net load [257] to us under 40 CFR Part 75, and that the proposed GHG standards of performance for new EGUs are expressed in terms of gross generation (although we sought comment on the use of net generation instead). We therefore specifically seek comment on whether the goals and reporting requirements for existing EGUs should be expressed in terms of

[254] We also recognize that even under a mass-based approach, adjustments may be appropriate in some circumstances to address interstate effects, such as when measures undertaken pursuant to one state's plan are expected to be associated with decreases in fossil fuel-fired generation and CO_2 emissions in another state. These issues are discussed below in Section VIII on state plans.

[255] As discussed below in Section VIII on state plans, we are similarly proposing that states choosing a rate-based form of emission performance level for their plans should establish a requirement for affected EGUs to report hourly net energy output.

[256] For some EGUs, total net or gross energy output also includes useful thermal output, in addition to either net or gross electric energy output.

[257] Some EGUs report gross steam output instead of gross electrical load.

gross generation instead of net generation for consistency with existing reporting requirements and with the proposed requirements under the GHG standards of performance for new EGUs.

The final aspect noted above has to do with the severability of the four building blocks, discussed in Section VI above, upon which the goals are based. Because the building blocks can be implemented independently of one another and the goals are the sum of the emission reductions from all of the building blocks, if any of the building blocks is found to be an invalid basis for the ''best system of emission reduction . . . adequately demonstrated,'' the goals would be adjusted to reflect the emissions reductions from the remaining building blocks. As noted above, the state goals that would result from any combination of the building blocks can be computed from data included in the Goal Computation TSD and its appendices using the methodology described below and in that TSD.

We invite comment on all aspects of the proposed form of the goals.

C. Proposed Goals and Computation Procedure

The EPA has developed proposed goals for state plans reflecting application of the BSER, based on all four building blocks described earlier, to pertinent data for each state. The goals are intended to represent CO_2 emission rates achievable by 2030 after a 2020–2029 phase-in period on an output-weighted-average basis collectively by all of a state's affected EGUs, with certain computation adjustments described below to reflect the potential to achieve mass emission reductions by avoiding fossil fuel-fired generation. For each state, in addition to the final goal, the EPA has developed an interim goal that would apply during the 2020–2029 period on a cumulative or average basis as the state progresses toward the final goal. The proposed goals are set forth in Table 8 below, followed by a description of the computation methodology. (The issue of how states could demonstrate emission performance consistent with the interim and final goals is addressed in Section VIII on state plans.)

TABLE 8—PROPOSED STATE[258] GOALS

[Adjusted output-weighted-average pounds of CO_2 per net MWh from all affected fossil fuel-fired EGUs]

State	Interim goal	Final goal
Alabama	1,147	1,059
Alaska	1,097	1,003
Arizona *	735	702
Arkansas	968	910
California	556	537
Colorado	1,159	1,108
Connecticut	597	540
Delaware	913	841
Florida	794	740
Georgia	891	834
Hawaii	1,378	1,306
Idaho	244	228
Illinois	1,366	1,271
Indiana	1,607	1,531
Iowa	1,341	1,301
Kansas	1,578	1,499
Kentucky	1,844	1,763
Louisiana	948	883
Maine	393	378
Maryland	1,347	1,187
Massachusetts	655	576
Michigan	1,227	1,161
Minnesota	911	873
Mississippi	732	692
Missouri	1,621	1,544
Montana	1,882	1,771
Nebraska	1,596	1,479
Nevada	697	647
New Hampshire	546	486
New Jersey	647	531
New Mexico *	1,107	1,048
New York	635	549
North Carolina	1,077	992
North Dakota	1,817	1,783
Ohio	1,452	1,338
Oklahoma	931	895
Oregon	407	372
Pennsylvania	1,179	1,052
Rhode Island	822	782
South Carolina	840	772
South Dakota	800	741
Tennessee	1,254	1,163
Texas	853	791
Utah *	1,378	1,322
Virginia	884	810
Washington	264	215
West Virginia	1,748	1,620
Wisconsin	1,281	1,203
Wyoming	1,808	1,714

* Excludes EGUs located in Indian country within the state.

The proposed goals are expressed as adjusted output-weighted-average emission rates for all affected EGUs in a state. As discussed earlier in this section, a goal expressed as an unadjusted output-weighted-average emission rate would fail to account for mass emission reductions from reductions in the total quantity of fossil fuel-fired generation associated with state plan measures that increase low- or zero-carbon generating capacity or demand-side energy efficiency. Accordingly, under the proposed goals, the emission rate computation includes an adjustment designed to reflect those mass emission reductions. The adjustment is made by estimating the annual net generation associated with an achievable amount of qualifying new low-carbon and zero-carbon generating capacity, as well as the annual avoided generation associated with an achievable portfolio of demand-side energy efficiency measures, and adding those MWh amounts to the energy output from affected units that would have been used in an unadjusted output-weighted-average emission rate computation.[259] Mathematically, this adjustment has the effect of spreading the measured CO_2 emissions from the state's affected EGUs over a larger quantity of energy output, thus resulting in an adjusted emission rate lower than the unadjusted emission rate. (As discussed below in Section VIII on state plans, we are proposing that a state could make analogous adjustments to compliance measurement approaches under its state plan, thereby enabling the state to adopt an emission rate-based form of emission performance level while still being able to rely on low- or zero-carbon capacity deployment programs and demand-side energy efficiency as components of its plan.)

The methodology used to compute each state's proposed goal is summarized on a step-by-step basis below. The methodology is described in more detail in the Goal Computation TSD, which includes a numerical example illustrating the full procedure. The development of the data inputs used in the computation procedure is discussed in Section VI above and in the Greenhouse Gas Abatement Measures TSD.

Step 1 (compilation of baseline data). On a state-by-state basis, we obtained total annual quantities of CO_2 emissions, net generation (MWh), and capacity (MW) from reported 2012 data for all affected EGUs.[260] For each state,

[258] The EPA has not developed goals for Vermont and the District of Columbia because current information indicates those jurisdictions have no affected EGUs. Also, as noted above, the EPA is not proposing goals for Indian country or U.S. territories at this time.

[259] In the case of new capacity that is not zero-carbon, an adjustment would also be required to the emissions value used in computing the weighted-average emission rate. This procedure is discussed further in the Goal Computation TSD.

[260] EGUs whose capacity, fossil fuel combustion, or electricity sales were insufficient to qualify them as affected EGUs were not included in the goal computations. Most simple cycle combustion

Continued

we aggregated the 2012 data for all coal-fired steam EGUs as one group, all oil- and gas-fired steam EGUs as a second group, and all NGCC units as a third group. We aggregated the 2012 data for all remaining affected EGUs (i.e., integrated gasification combined-cycle (IGCC) units and any simple-cycle combustion turbines satisfying relevant thresholds for qualification as affected EGUs) as a fourth, ''other'' group.[261] To these totals for affected EGUs operating in 2012, we added estimates for other EGUs not yet in operation in 2012 that are affected EGUs for purposes of this emission guideline.[262] Capacity and emission rate data inputs for the post-2012 affected EGUs were obtained from the NEEDS database maintained by the EPA for use with the Integrated Planning Model (IPM). Generation data inputs for the post-2012 affected EGUs were estimated based on the average 2012 utilization rates for recently constructed EGUs of the same types; for example, we estimated in this step that the post-2012 NGCC units would operate at a 55 percent utilization rate on average.

Step 2 (application of building block 1). The total CO_2 emissions amount for the coal-fired steam EGU group in each state from Step 1 was reduced by six percent, reflecting our assessment of the average opportunity to reduce CO_2 emission rates across the existing fleet of coal-fired steam EGUs through heat rate improvements that is technically achievable at a reasonable cost.

Step 3 (application of building block 2). If the generation data for the NGCC group in a state developed in Step 1 showed average annual utilization below 70 percent of those units' maximum possible output, and the generation data developed in Step 1 also included generation from the coal-fired steam or oil/gas-fired steam EGU groups in that state, the generation and emissions figures for the NGCC group were increased, and the generation and emissions figures for the coal-fired and oil/gas-fired steam EGU groups from Step 2 were proportionately[263] decreased, to reflect an estimated potential increase in utilization of the NGCC group to a maximum of 70 percent. In this step, the total (across all four groups) of the state's fossil fuel-fired generation was maintained at the amount computed in Step 1, but to the extent that in the analysis a portion of the total fossil generation was shifted from the coal-fired and oil/gas-fired steam EGU groups, which have higher CO_2 emission rates, to the NGCC group, which has a lower CO_2 emission rate, the total (across all four groups) of the state's CO_2 emissions was reduced.[264]

Step 4 (application of building block 3). We estimated the total quantities of generation from renewable generating capacity and from under-construction or preserved nuclear capacity for each state using the approaches described in Section VI.C.3 above. Separate estimates of renewable generation were computed for each year of the plan period for each state based on the state's 2012 renewable generation and a regional growth factor. Nuclear generation was estimated as the amount of under-construction and preserved nuclear capacity for each state operated at a utilization rate of 90 percent, consistent with recent industry-wide average utilization rates for nuclear units.

Step 5 (application of building block 4). We estimated the total MWh amount by which generation from each state's affected EGUs would be cumulatively reduced in each year of the plan period associated with implementation in that state of demand-side energy efficiency programs resulting in annual incremental reductions in the state's electricity usage (relative to usage absent those programs) of 1.5 percent each year, as described in Section VI.C.4 above. Separate estimates were developed for each year to reflect the fact that energy efficiency programs that are implemented on an ongoing basis would be expected to produce larger cumulative impacts on total annual electricity usage over time. For states that are net importers of electricity, the estimated reduction in the generation by the state's affected EGUs was scaled down to reflect an expectation that a portion of the generation avoided by the demand-side energy efficiency would occur at EGUs in other states.

Step 6 (computation of annual rates). We computed adjusted output-weighted-average CO_2 emission rates for each state by dividing (1) the total CO_2 emissions for the coal-fired steam EGU, oil- and gas-fired steam EGU, NGCC unit, and ''other'' affected fossil EGU groups from Step 3 above by (2) the total of (a) the total net energy output (expressed in MWh) for the four groups from Step 1 above plus (b) the estimated annual net generation from renewable and nuclear generating capacity from Step 4 above plus (c) the estimated cumulative annual MWh amount saved through demand-side energy efficiency from Step 5 above.[265] We performed these computations separately for each year from 2020 to 2029, using the respective cumulative annual MWh savings figures developed in Steps 4 and 5.

Step 7 (computation of interim and final goals). The final 2030 goal for each state is the annual rate computed for 2029 for the state from Step 6 above. We computed the 2020–2029 interim goal for each state as the simple average of the annual rates computed for each of the years from 2020 to 2029 for the state from Step 6 above.

It bears emphasis that the procedure described above is proposed to be used only to determine state goals, and the particular data inputs used in the procedure are not intended to represent specific requirements that would apply to any individual EGU or to the collection of EGUs in any state. The specific requirements applicable to individual EGUs, to the EGUs in a given state collectively, or to other affected entities in the state, would be based on the standards of performance established through that state's plan. The details of how states could attain emission performance levels consistent with the goals through different state plan approaches that recognize emission reductions achieved through all the building blocks are discussed further in Section VIII on state plans.

We invite comment on all aspects of the goal computation procedure. (Note that we also invite comment on certain specific alternate data inputs to the procedure in Section VI.C above.) We also specifically invite comment on the state-specific historical data to which

turbines were excluded on this basis. See the applicability criteria described in Section V.B. above.

[261] The emission and generation totals for the ''other'' group also reflect the portion of affected cogeneration units' total CO_2 emissions and total energy output corresponding to those units' useful thermal output.

[262] Assuming it meets other applicability criteria, an EGU would be affected if it had commenced construction by January 8, 2014 (the data of **Federal Register** publication of the proposed GHG NSPS for new EGUs).

[263] For example, if the data developed in Step 1 showed equal quantities of MWh generated by the coal-fired steam EGU group and the oil/gas-fired steam EGU group, then any overall reduction in the MWh generated by these two groups due to a commensurate increase in the MWh generated by the less carbon-intensive NGCC group would be split equally between the coal-fired steam group and the oil/gas-fired steam group.

[264] We did not estimate any change in utilization, generation, or emissions for the state's ''other'' group of IGCC units and simple-cycle combustion turbines in Step 3.

[265] Expressed as a formula, the equation for the annual rate computation is:

[(Coal gen. × Coal emission rate) + (OG gen. × OG emission rate) + (NGCC gen. × NGCC emission rate) + ''Other'' emissions]/[Coal gen. + OG gen. + NGCC gen. + ''Other'' gen. + Nuclear gen. + RE gen. + EE gen.]

This formula and its elements are further explained in the Goal Computation TSD, as well as in the text above.

the building blocks are applied in order to compute the state goals, as well as the state-specific data used to develop the state-specific data inputs for building blocks 3 and 4. These data are contained in the Goal Computation TSD and the Greenhouse Gas Abatement Measures TSD.

With respect to building block 2, we specifically request comment on the following alternate procedure: In Step 3, to the extent that generation from a state's NGCC group was increased consistent with the NGCC utilization rate target, in order to maximize the resulting emission reductions, we would decrease generation from the state's coal-fired steam group first, and then decrease generation from the state's oil/gas-fired steam group (instead of decreasing generation from the coal-fired steam and oil/gas-fired steam groups proportionately).

With respect to building block 4, we specifically invite comment on the alternative in Step 5 of scaling up the estimated reduction in the generation by affected EGUs in net electricity-exporting states to reflect an expectation that a portion of the generation avoided in conjunction with the demand-side energy efficiency efforts of other, net electricity-importing states would occur at those EGUs, analogous to the proposed adjustment for net electricity-importing states described in Step 5. We also request comment on the alternative of making no adjustment in Step 5 for either net electricity-importing or net electricity-exporting states. These alternatives are discussed in the Goal Computation TSD.

We also request comment on whether CO_2 emission reductions associated with other measures not currently included in any of the four proposed building blocks should be included in the state goals.

D. State Flexibilities

As promulgated in the final rule following consideration of comment, the state-specific goals will be binding emission guidelines. States' ability to achieve emission performance levels consistent with the binding goals is enhanced by several distinct types of flexibility: (i) Choices as to the measures employed, including the timing of their implementation; (ii) the ability to translate from a rate-based form of goal to a mass-based form of goal; and (iii) the opportunity to pursue multi-state plan approaches.

First, a core flexibility provided under CAA section 111(d) is that while states are required to establish standards of performance that reflect the degree of emission limitation from application of the control measures that the EPA identifies as the BSER, they need not mandate the particular control measures the EPA identifies as the basis for its BSER determination. In developing the building block data inputs applied to each state's historical data to develop the goals, the EPA targeted reasonably achievable rather than maximum performance levels. The overall goals therefore represent reasonably achievable emission performance levels that provide states with flexibility to pursue some building blocks more extensively and others less extensively than the degree reflected in the EPA's data inputs while meeting the overall goals. States can also choose to include in their plans other measures that reduce CO_2 emissions at affected EGUs but that are not included in the building blocks.

Further, by allowing states to demonstrate emission performance by affected EGUs on an average basis over a multi-year interim plan period of as long as ten years, the EPA's proposed approach increases states' flexibility to choose among alternative potential plan measures. For example, by taking advantage of the multi-year flexibility, a state could choose to rely more heavily in its plan on measures whose effectiveness tends to grow over time, such as demand-side energy efficiency programs. This flexibility could also help states address concerns about stranded assets, for example, by enabling states to defer imposition of requirements on EGUs that may be scheduled to retire after 2020 but before 2029.

The second type of flexibility noted above is that while the EPA is proposing to establish goals in an emission rate-based form, we are also proposing to provide states with the flexibility to translate the rate-based goals to mass-based goals in order to accommodate states' potential interest in having emission performance requirements measured in absolute tons. For example, the northeastern and Mid-Atlantic states that currently participate in the mass-based Regional Greenhouse Gas Initiative (RGGI) may choose to develop state plans (or a multi-state plan, as noted below) establishing mass-based emission performance levels designed to be met at least in part through standards of performance based on RGGI's existing market-based CO_2 emission budget trading program. Because the use of mass-based plans can simplify the process of accounting for the CO_2 reduction impacts of a variety of measures, the EPA believes the flexibility to adopt mass-based emission performance levels can facilitate plan development and could be attractive to states that do not already participate in mass-based emission reduction programs as well.

Third, the EPA's approach allows states to submit multi-state plans. The EPA expects this flexibility to reduce the cost of achieving the state goals and therefore expects it to be attractive to states. For example, the RGGI-participating states could choose to submit a multi-state mass-based plan that demonstrates emission performance by affected EGUs on a multi-state basis. Additional states may also choose to join a multi-state plan. The mechanics of translating rate-based goals into mass-based goals and considerations related to multi-state plans are discussed below in Section VIII on state plans.

Some stakeholders have suggested that states themselves should be allowed to quantify the level of emission reduction resulting from the application of BSER or, if the EPA establishes goals, the states should be allowed to adjust the goals or to treat the goals established by the EPA as advisory rather than binding. Consistent with the existing implementing regulations for CAA section 111(d) at 40 CFR part 60, this quantification is the EPA's role.[266] As discussed in the Legal Memorandum, CAA section 111(d) directs the EPA to ''prescribe regulations which shall establish a procedure similar to that provided by [CAA section 110] under which each State shall submit'' a section 111(d) state plan. As noted in Section II.D of this preamble, the EPA promulgated implementing regulations in 1975, and has revised parts of them since. The regulations set out a multi-step process for the development and approval of state plans, and assign responsibility for the various steps in the process to the EPA or the states. The regulations provide that the EPA is to promulgate an ''emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for'' affected sources.[267] In this manner, the regulations make clear that the EPA determines the BSER. In this rulemaking, as discussed above, the EPA identifies the BSER. In addition, in this rulemaking, the EPA applies the BSER to each state, and then, for each state, calculates the average emission rate that, in the words of the regulations just quoted, ''reflects the application of

[266] 40 CFR 60.22(b)(5). We do not propose to re-open that portion of the implementing regulations in this rulemaking.

[267] *Id.*

the [BSER].'' That average emission rate is the state goal.

By the same token, because the state goals are an integral part of the emission guidelines that the framework regulations authorize the EPA to establish, the goals are binding, and the states, in their CAA section 111(d) plans, must meet those goals and may not make them less stringent. This matter, too, is resolved by the implementing regulations.[268] To reiterate, the proposed state goals represent the level of performance that is achievable through application of the BSER to the pertinent data for each individual state. States have the opportunity to comment on the proposed BSER, the proposed methodology for computing state goals based on application of the BSER, and the state-specific data that is proposed for use in the computations. We expect that the states will have an adequate opportunity to comment on the state goals during the comment period. Once the final goals have been promulgated, and adjusted as may be appropriate based on comments to address any factual errors in the analysis, the states will be able to meet them because they will represent the application of BSER to the states' affected sources. In addition, states have several types of flexibilities in developing their state plans: They have flexibility regarding the selection of the measures upon which they choose to rely and a 10-year time period over which to reach full implementation of these measures, and they can use rate-based or mass-based approaches. In addition, as we have noted, multi-state coordination offers states an opportunity to achieve additional emission reductions and reduce implementation costs. These flexibilities, discussed further in Section VIII of this preamble, ensure that states will be able to achieve their final CO_2 emission performance goals and that no special provision for state adjustment of goals outside the normal notice-and-comment rulemaking process is warranted.[269]

E. Alternate Goals Offered for Comment and Other Approaches Considered

In addition to the proposed state-specific emission rate-based goals described above, the EPA has developed for public comment an alternate set of goals reflecting less stringent application of the building blocks and a shorter implementation period. The alternate final goals represent emission performance that would be achievable by 2025, after a 2020–2024 phase-in period, with interim goals that would apply during the 2020–2024 period on a cumulative or average basis as states progress toward the final goals.

Because the time period for implementation relates directly to the emission reductions that are achievable and therefore what measures, and at what level of stringency, constitute the BSER, the alternate goals reflect several differences in data inputs from the proposed goals. Specifically, a value of four percent (instead of six percent) was used for the potential improvement in carbon intensity of coal-fired EGUs in Step 2; a value of 65 percent (instead of 70 percent) was used for the potential annual utilization rate of NGCC units in Step 3; and a value of one percent (instead of 1.5 percent) was used for the annual incremental electricity savings achievable through a portfolio of demand-side energy efficiency programs in Step 5. (No change was made to the data inputs regarding less carbon-intensive generating capacity in Step 4.) As noted above, the alternate goals also reflect a shortening of the proposed phase-in period from ten years (2020–2029) to five years (2020–2024) to reflect an expectation that less stringent goals could be achieved in less time. Steps 5, 6, and 7 of the goal computation procedure therefore were performed for the span of years from 2020 to 2024 rather than for the span from 2020 to 2029. The alternate goals are set forth in Table 9 below.

TABLE 9—ALTERNATE STATE[270] GOALS

[Adjusted output-weighted-average pounds of CO_2 per net MWh from all affected fossil fuel-fired EGUs]

State	Interim goal	Final goal
Alabama	1,270	1,237
Alaska	1,170	1,131
Arizona *	779	763
Arkansas	1,083	1,058
California	582	571
Colorado	1,265	1,227
Connecticut	651	627
Delaware	1,007	983
Florida	907	884
Georgia	997	964
Hawaii	1,446	1,417
Idaho	261	254
Illinois	1,501	1,457
Indiana	1,715	1,683
Iowa	1,436	1,417
Kansas	1,678	1,625
Kentucky	1,951	1,918
Louisiana	1,052	1,025
Maine	418	410
Maryland	1,518	1,440
Massachusetts	715	683
Michigan	1,349	1,319
Minnesota	1,018	999
Mississippi	765	743
Missouri	1,726	1,694
Montana	2,007	1,960
Nebraska	1,721	1,671
Nevada	734	713
New Hampshire	598	557
New Jersey	722	676
New Mexico *	1,214	1,176
New York	736	697
North Carolina	1,199	1,156
North Dakota	1,882	1,870
Ohio	1,588	1,545
Oklahoma	1,019	986
Oregon	450	420
Pennsylvania	1,316	1,270
Rhode Island	855	840
South Carolina	930	897
South Dakota	888	861
Tennessee	1,363	1,326
Texas	957	924
Utah *	1,478	1,453
Virginia	1,016	962
Washington	312	284
West Virginia	1,858	1,817
Wisconsin	1,417	1,380
Wyoming	1,907	1,869

* Excludes EGUs located in Indian country in the state.

The EPA recognizes that its approach to the alternate goals, comprising less stringent requirements in each of the building blocks to be achieved over a shorter compliance horizon, follows the logic of including time as one of the functions of the BSER determination. At the same time, we also recognize that the components of the alternate goals may reflect an overly conservative approach. Specifically, the alternate goals as set forth above may underestimate the extent to which the key elements of the four building blocks—achieving heat rate improvements at EGUs, switching generation to NGCC facilities, fostering the penetration of renewable resources or improving year-to-year end-use energy efficiency—can be achieved rapidly while preserving reliability and remaining reasonable in cost. Accordingly, we request comment on the alternate goals, particularly with respect to whether any one or all of the building blocks in the alternate goals

[268] *Id.* We do not propose to re-open that portion of the implementing regulations in this rulemaking.

[269] In the event that a state becomes concerned about its ability to meet the goal that the EPA promulgates for it, the state may submit to the EPA a petition for reconsideration, if that petition is based on relevant information not available during the comment period. *See* CAA section 307(d)(7)(B).

[270] See footnote accompanying Table 8 above.

can be applied at a greater level of stringency: Can the heat rate improvement value be set at a level above four percent, even six percent? Can NGCC capacity be dispatched at a utilization rate above 65 percent? Can annual incremental electricity savings be achieved at a rate higher than one percent?

It is worth noting that the EPA projects that the alternate goals will achieve emission reductions equal to 23 percent below 2005 level in 2025. The EPA's analysis shows that under the proposed goals described in Section VII.C above, power sector emissions will be 29 percent below 2005 levels in 2025, suggesting that the kinds of changes contemplated in the four building blocks, even as early as 2025, will be yielding reductions far greater than the 23 percent projected for the alternate goals as set forth above in this subsection.

The EPA has considered other approaches to setting goals. In particular, given the interconnected nature of the power sector and the importance of opportunities for shifting generation among EGUs, we considered whether goals should be set on a multi-state basis reflecting the scope of existing regional transmission control areas. We also considered whether goals should be set on a state-specific basis, but regional rather than state-specific evaluations should be used to assess the estimated opportunities to reduce utilization of the most carbon-intensive EGUs by shifting generation to less carbon-intensive EGUs. A potential advantage of using regional evaluations is the ability to recognize additional emission reduction opportunities that would be available at reasonable costs based on a more complete representation of the capabilities of existing infrastructure to accommodate shifts in generation among EGUs in multiple states. We request comment on whether, and if so how, the EPA should incorporate greater consideration of multi-state approaches into the goal-setting process, and on the issue of whether, and if so how, the potential cost savings associated with multi-state approaches should be considered in assessing the reasonableness of the costs of state-specific goals.

F. Reliable Affordable Electricity

Many stakeholders raised concerns that this regulation could affect the reliability of the electric power system. The EPA agrees that reliability must be maintained and in designing this proposed rulemaking has paid careful attention to this issue. The EPA has met on several occasions with staff and managers from the Department of Energy and the Federal Energy Regulatory Commission to discuss our approach to the rule and its potential impact on the power system. EPA staff and managers have also had numerous discussions with state public utility commissioners and their staffs to get their suggestions and advice concerning this rule, including how to address reliability concerns.

In addition, the EPA met with independent system operators several times to discuss any potential impact of this rule on grid reliability. The ISO/RTO Council, a national organization of electric grid operators, offered analytic support to help states design programs that do not compromise the regional bulk power system. They also offered to help states develop regional approaches which may reduce costs and strengthen the reliability of the electricity grid. Specifically, the ISO/RTO Council has suggested that ISOs and RTOs could provide analytic support to help states develop and implement their plans. The ISOs and RTOs have the capability to model the system-wide effects of individual state plans. Providing assistance in this way, they felt, would allow states with borders that fall within an ISO or RTO footprint to assess the system-wide impacts of potential state plan approaches. In addition, as the state implements its plan, ISO/RTO analytic support would allow the state to monitor the effects of its plan on the regional electricity system. ISO/RTO analytic capability could help states assure that their plans are consistent with region-wide system reliability. The ISO/RTO Council suggested that the EPA ask states to consult with the applicable ISO/RTO in developing their state plans. The EPA agrees with this suggestion and encourages states with borders that fall within one or more ISO or RTO footprints to consult with the relevant ISOs/RTOs.

The EPA has met with the U.S. Department of Agriculture as well to discuss how we can address the concerns of small, relatively isolated power generators in rural America and especially the electric cooperatives. Many of these entities have special challenges, as they may have small, older carbon-intensive assets and might have particular challenges meeting carbon requirements.

With all of this in mind, the EPA in determining the BSER looked specifically at the reasonableness of the costs of control options in part to ensure that the options would not have a negative effect on system reliability. The BSER, including each of the building blocks, was determined to be feasible at reasonable costs over the timeframe proposed here. Further, under the Clean Air Act the states are given the flexibility to design state plans that include any measure or combination of measures to achieve the required emission limitations. States are not required to use each of the measures that the EPA determines constitute the BSER or use those measures to the same degree or extent that the EPA determines is feasible at a reasonable cost. Thus, each state has the flexibility to choose the most cost-effective measures given that state's energy profile and economy, as long as the state achieves the reductions necessary to meet its goal. Many market-based approaches which states may choose reduce the costs of compliance. They can allow certain units that are seldom used to remain in operation if they are needed for reliability purposes. Multi-state approaches also reduce costs and stress on the grid and so can help to reduce any concern about electricity reliability.

States may choose measures that would ease pressures on system reliability. This is true for many demand-side management approaches, including programs to encourage end-use energy efficiency, distributed generation, and combined heat and power, which actually reduce demand for centrally generated power and thus relieve pressure on the grid.

The EPA is proposing a 10-year period over which to achieve the full required CO_2 reductions, and we would expect this to further relieve any pressure on grid reliability. This relatively long planning and implementation period provides states with substantial flexibility regarding methods and timing of achieving emission reductions.

The EPA's supporting analysis for this rule includes an examination of the effects of the rule on regional resource adequacy.[271] The EPA's analysis looked at the types of changes in the generation fleet that were projected to occur through retirements, additional generation and energy efficiency. The analysis did not raise concerns over regional resource adequacy. The EPA further examined how the policy options impacted the flows and transfers of electricity that occur to meet reserve margins. None of the interregional changes in the policy cases suggested that there would be increases in flows that would raise significant concerns about grid congestion or grid management. Moreover, the time

[271] See the Resource Adequacy and Reliability Analysis TSD, available in the docket.

horizon for compliance with this rule will permit environmental and reliability planners to coordinate these changes and address potential concerns before they arise.

The EPA concludes that the proposed rule will not raise significant concerns over regional resource adequacy or raise the potential for interregional grid problems. The EPA believes that any remaining local issues can be managed through standard reliability planning processes. The flexibility inherent in the rule is responsive to the CAA's recognition that state plans for emission reduction can, and must, be consistent with a vibrant and growing economy and reliable, affordable electricity to support that economy. The EPA welcomes comments and suggestions on this issue.

VIII. State Plans

A. Overview

After the EPA establishes the state-specific rate-based CO_2 goals in the emission guidelines, as described in Section VII above, each state must then develop, adopt, and submit its state plan under CAA section 111(d). To do so, the state must first determine the emission performance level it will include in its plan, which entails deciding whether it will adopt the rate-based CO_2 goal set by the EPA or translate the rate-based goal to a mass-based goal.

The state must then establish an emission standard or set of emission standards, and, perhaps other measures, along with implementing and enforcing measures, that will achieve a level of emission performance that is equal to or better than the level specified in the state plan.

The state must then adopt the state plan through certain procedures, which include a state hearing. Within the time period specified in the emission guidelines (from as early as June 30, 2016 to as late as June 30, 2018, depending on the state's circumstances), the state must submit its complete state plan to the EPA. The EPA then must determine whether to approve or disapprove the plan. If a state does not submit a plan, or if the EPA does not approve a state's plan, then the EPA must establish a plan for the state.

As discussed in Section V.D of this preamble, in the case of a tribe that has one or more affected EGUs located in its area of Indian country, if the EPA determines that a CAA section 111(d) plan is necessary or appropriate, the EPA has the responsibility to establish a CAA section 111(d) plan for that area of Indian country where affected sources are located unless the tribe on whose lands an affected source (or sources) is located seeks and obtains authority from the EPA to establish a plan itself, pursuant to the Tribal Authority Rule.[272] The agency is soliciting comment on aspects of such CAA section 111(d) plans, as described in Section V.D of this preamble.

This section is organized into six parts. First, we discuss the types of plans that we propose states could submit. Second, we address timing for plan implementation and achievement of state emission performance goals for affected EGUs. Third, we discuss the proposed state plan approvability criteria. Fourth, we summarize the proposed components of an approvable state plan. Fifth, we address the proposed process and timing for submittal of state plans. Sixth, we identify several key considerations for states in developing and implementing plans, including: Affected entities with obligations under a plan; treatment of existing state programs; incorporation of renewable energy (RE) and demand-side energy efficiency (EE) programs in certain plans; quantification, monitoring, and verification of RE and demand-side EE measures; reporting and recordkeeping for affected entities; treatment of interstate effects; and projection of emission performance. Finally, we discuss a number of additional factors that could help states meet their CO_2 emission performance goals, and we note certain resources that are available to facilitate plan development and implementation. Additional discussion of some of the topics covered in this section can be found in the State Plan Considerations TSD and Projecting EGU CO_2 Emission Performance in State Plans TSD, both of which are in the rulemaking docket.

B. Approach

In this action, the EPA is proposing emission guidelines in the form of state-specific CO_2 emission performance goals. In addition, the EPA is proposing guidelines for states to follow in developing plans to establish and implement CO_2 emission standards for affected EGUs. The proposed plan guidelines include four general plan approvability criteria, twelve required components for a state plan to be approvable, the process and timing for state plan submittal and review, and the process and timing for demonstrating achievement of the CO_2 goals. These are described below.

The EPA recognizes that each state has different state policy considerations—including varying emission reduction opportunities and existing state programs and measures—and that the characteristics of the electricity system in each state (e.g., utility regulatory structure, generation mix, electricity demand) also differ. The agency also anticipates—and supports—states' commitments to a wide range of policy preferences that could encompass those of states like Kentucky, West Virginia and Wyoming seeking to continue to feature significant reliance on coal-based generation; states like Minnesota, Colorado, California and the nine RGGI states seeking to build on actions and policies they have already undertaken; and states like Washington and Oregon seeking to integrate sustainable forestry and renewable energy strategies. The proposed plan guidelines provide states with options for establishing emission standards in a manner that accommodates a diverse range of state approaches. Each state will have significant flexibility to determine how to best achieve its CO_2 goals in light of its specific circumstances, including addressing concerns particular to the state, such as employment transition issues, as it designs and implements its plan over multiple years. As an example, the RGGI states' implementation of their mass-based emission budget trading program raises proceeds through allowance auctions and uses those proceeds to advance programs promoting and expanding end-use energy efficiency. States could address analogous priorities, such as employment transition, through a similar mechanism.

The proposed plan guidelines would also allow states to collaborate and to develop plans that provide for demonstration of emission performance on a multi-state basis, in recognition of the fact that electricity is transmitted across state lines, and that state measures may impact, and may be explicitly designed to reduce, regional EGU CO_2 emissions. The EPA also recognizes that multi-state collaboration would likely offer lower-cost approaches to achieving CO_2 emission reductions. With this in mind, we are proposing to provide states with additional time to submit complete plans if they do so as part of a multi-state plan, and we solicit comment on other potential mechanisms for fostering multi-state collaboration.

1. State Plan Approaches

a. Overview

Although state CAA section 111(d) plans must assure that the emission performance level is achieved through

[272] See 40 CFR 49.1 to 49.11.

reductions at the affected sources, we believe that different types of state plans could be constructed that make use of the diversity of measures available to achieve CO_2 emission reductions. Based on the EPA's outreach efforts, it is clear that states are considering different types of plans.

Three important issues in the design of state plans include: (1) Whether the plan should require the affected EGUs to be subject to emission limits that assure that the emission performance level is achieved, or instead, whether the plan could rely on measures, such as renewable energy (RE) or demand-side energy-efficiency (EE), to assure the achievement of part of the emission performance level; (2) whether the responsibility for all of the measures other than emission limits should fall on the affected EGUs, or, instead, could fall on entities other than affected EGUs; and (3) whether the fact that requiring all measures relied on to achieve the emission performance level to be included in the state plan renders those measures federally enforceable. These issues and the EPA's proposed approach are addressed in detail in the sections that follow.

The EPA is proposing that all measures relied on to achieve the emission performance level be included in the state plan, and that inclusion in the state plan renders those measures federally enforceable.

In light of current state programs, and of stakeholder expressions of concerns over the above-noted issues, including legal enforcement considerations, with respect to those programs, the EPA is proposing to authorize states either to submit plans that hold the affected EGUs fully and solely responsible for achieving the emission performance level, or to submit plans that rely in part on measures imposed on entities other than affected EGUs to achieve at least part of that level, as well as on measures imposed on affected EGUs to achieve the balance of that level. The EPA requests comment on this proposed approach, as opposed to the approach under which state plans simply would be required to hold the affected EGUs fully and solely responsible for achieving the emission performance level.

In addition, the EPA is soliciting comment on several other types of state plans that may assure the requisite level of emission performance without rendering certain types of measures federally enforceable and that limit the obligations of the affected EGUs.

b. Portfolio Approach

In assessing the types of state plans to authorize, the EPA reviewed existing state programs that reduce CO_2 emissions from fossil fuel-fired power plants. Existing state programs are particularly informative for this purpose in light of the fact that CAA section 111(d) gives states the primary responsibility for designing their own state plans for submission to the EPA. Many of these existing state programs, as summarized above, include measures such as renewable energy (RE) and demand-side energy efficiency (EE) programs, which impose responsibilities on a range of entities, including state agencies, for assuring implementation of actions that result in reduced utilization of, and therefore reduced emissions from, fossil fuel-fired EGUs, and do not impose legal responsibilities for those emission reductions on the EGUs themselves.

In addition, during the EPA's extensive outreach efforts, many stakeholders expressed concern over the extent of responsibility that fossil fuel-fired EGUs would be required to bear for the required emission reductions, in particular, those associated with RE and demand-side EE measures. These stakeholders recommended that the EPA authorize states to achieve emission reductions from RE and demand-side EE measures by imposing requirements on entities other than fossil fuel-fired EGUs, and without imposing legal responsibility for these emission reductions on those EGUs.

Accordingly, the EPA is proposing to authorize a state plan to adopt what we refer to as a ''portfolio approach,'' in which the plan would include emission limits for affected EGUs along with other enforceable measures, such as RE and demand-side EE measures, that reduce CO_2 emissions from affected EGUs. Under this approach, it would be all of the measures combined that would be designed to achieve the required emission performance level for affected EGUs as expressed in the state goal. Under this approach, the emission limits enforceable against the affected EGUs would not, on their own, assure, or be required to assure, achievement of the emission performance level. Rather, the state plan would include measures enforceable against other entities that support reduced generation by, and therefore CO_2 emission reductions from, the affected EGUs. As noted, these other measures would be federally enforceable because they would be included in the state plan. A portfolio approach could be used for state plans that establish the emission performance level on either an emission rate basis or a mass emissions basis.

In addition, a portfolio approach could either be what we refer to as ''utility-driven'' or ''state-driven,'' depending on the utility regulatory structure in a state. Under a utility-driven approach, a state plan may include, for example, measures implemented consistent with a utility integrated resource plan, including both measures that directly apply to affected EGUs (e.g., repowering or retirement of one or more EGUs) as well as RE and demand-side EE measures that avoid EGU CO_2 emissions.[273] Under a state-driven approach, the measures in a state plan would include emission standards for affected EGUs, as well as requirements that apply to entities other than affected EGUs, for example, renewable portfolio standards (RPS) or end-use energy efficiency resource standards (EERS), both of which often apply to electric distribution utilities.[274]

c. Obligations on Affected EGUs

The EPA is proposing to authorize state plans to adopt the portfolio approach and is proposing to interpret the CAA as allowing that approach, as described in more detail below. CAA section 111(d)(1) would certainly allow state plans to require the affected EGUs to be the sole entities legally responsible for achieving the emission performance level. The EPA is also soliciting comment on whether it can reasonably interpret CAA section 111(d)(1) to allow states to adopt plans that require EGUs and other entities to be legally responsible for actions required under the plan that will, in aggregate, achieve the emission performance level.

We note that some existing state programs, such as RGGI in the northeastern states, do impose the ultimate responsibility on fossil fuel-fired EGUs to achieve the required emission reductions, but are also designed to work either concurrently, or in an integrated fashion, with RE and demand-side EE programs that reduce the cost of meeting those emission limitations. These existing programs offer a possible precedent for another type of CAA section 111(d) state plan. Such a plan approach could rely on CO_2 emission standards enforceable against affected EGUs—whether in the form of

[273] In the case of a utility-driven portfolio approach, the vertically integrated electric utility implementing portfolio measures is also the owner and operator of affected EGUs.

[274] A state-driven portfolio approach is more likely in states that have instituted electricity sector restructuring, where electric utilities have typically been required by states to divest electric generating assets.

emission rate or mass limits—to ensure achievement of the required emission performance level, but also include enforceable or complementary RE and demand-side EE measures that lower cost and otherwise facilitate EGU emission reductions. Depending on the type of plan, these RE and demand-side EE measures could either be enforceable components of the plan (that is, the states could require affected EGUs or other affected entities to invest in RE or in demand-side EE programs) or be complementary to the plan. In this manner, RE and demand-side EE measures could be a major component of a state's overall strategy for reducing EGU CO_2 emissions at a reasonable cost.

It should be noted that state plan approaches that impose legal responsibility on the affected EGUs to achieve the full level of required emission performance could incorporate RE and demand-side EE measures regardless of whether the emission standards that those plans apply to the affected EGUs take the form of an emission rate or a mass limit. Plans with rate-based emission limits could incorporate enforceable RE and demand-side EE measures by adjusting an EGU's CO_2 emission rate when demonstrating compliance through either an administrative adjustment by the state or use of a tradable credit approach. (These actions would need to be enforceable components of a state plan to facilitate EGU compliance with emission rate limits and ensure that actions are properly quantified, monitored, and verified.) A state plan that imposes a mass limit on affected EGUs that is sufficiently stringent to achieve the emission performance level would not need to include RE or demand-side EE measures as an enforceable component of the plan to assure the achievement of that performance level. The mass limit itself would suffice. However, the state may wish to implement RE and demand-side EE measures as a complement to the plan to support achievement of the mass limit at lesser cost.

d. Federal Enforceability

Another concern expressed by some stakeholders is that including RE and demand-side EE measures in state plans would render those measures federally enforceable and thereby extend federal presence into areas that, to date, largely have been the exclusive preserve of the state and, in particular, state public utility commissions and the electric utility companies they regulate. These stakeholders suggest that states could rely on RE and demand-side EE programs as complementary measures to reduce costs for, and otherwise facilitate, EGU emission limits without including those measures in the CAA section 111(d) state plan. Under this suggested approach, the EGU emission limits would be federally enforceable, but RE and demand-side EE measures would serve as complementary measures and would not be enforceable under federal law; instead, they would remain enforceable under state law. According to stakeholders, those types of state programs, particularly because they are well-established, can be expected to achieve their intended results. Thus, they suggest that the states could conclude that those RE and demand-side EE measures would be beneficial in assuring the achievement of the required emission performance level by the affected EGUs specified in the CAA section 111(d) state plan, even without including those measures in the plan.

e. Plans With State Commitments

As another vehicle for approving CAA section 111(d) plans for states that wish to rely on state RE and demand-side EE programs but do not wish to include those programs in their state plans, the EPA requests comment on what we refer to as a ''state commitment approach.'' This approach differs from the proposed portfolio approach, described above, in one major way: Under the state commitment approach, the state requirements for entities other than affected EGUs would not be components of the state plan and therefore would not be federally enforceable. Instead, the state plan would include an enforceable commitment by the state itself to implement state-enforceable (but not federally enforceable) measures that would achieve a specified portion of the required emission performance level on behalf of affected EGUs. The agency requests comment on the appropriateness of this approach. The agency also requests comment on the policy ramifications of the following: Under this approach, the state programs upon which the state bases its commitment may, in turn, rely on compliance by third parties, and if those state programs fail to achieve the expected emission reductions, the state could be subject to challenges—including by citizen groups—for violating CAA requirements and, as a result, could be held liable for CAA penalties.

We also solicit comment on a variation of this state commitment plan approach that is also designed to address stakeholder concerns, noted above, about imposing sole legal responsibility on affected EGUs for achieving the emission performance level. With this variation, the state plan would in effect shift a portion of that responsibility to the state, in the following manner: The state plan would impose the full responsibility for achieving the emission performance level on the affected EGUs, but the state would credit the EGUs with the amount of emission reductions expected to be achieved from, for example, RE or demand-side EE measures. The state would then assume responsibility for that credited amount of emission reductions in the same manner as the state commitment plan approach discussed above. We solicit comment on whether, if the EPA were to conclude that CAA section 111(d) requires state plans to include standards of performance applicable to affected EGUs that achieve the emission performance level, this type of state plan would meet that requirement while also assuring those EGUs an important measure of support.

f. Legal Issues

The EPA is proposing to interpret the relevant provisions in CAA section 111 to authorize state plans that achieve emissions reductions from affected EGUs by means of the portfolio approach. CAA section 111(d)(1) requires each state to submit a plan that ''(A) establishes standards of performance for any existing source [for certain air pollutants] . . . and (B) provides for the implementation and enforcement of such standards of performance.'' CAA section 111(a)(1) defines a ''standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction . . . adequately demonstrated.''

These provisions make clear that emission limits that are enforceable against affected EGUs appropriately belong in state plans because they clearly are ''standards of performance.'' However, the terms of CAA section 111(d)(1) do not explicitly address whether, in addition to emission limits on affected EGUs, state plans may include other measures for achieving the emission performance level. Nor do they address whether entities other than affected EGUs may be subject to requirements that contribute to reducing EGU emissions. Under the U.S. Supreme Court's 1984 decision in *Chevron U.S.A. Inc.* v. *NRDC,* where the statute leaves a gap, the agency has discretion to fashion an interpretation

that is a reasonable construction of the statute.[275]

The EPA is proposing to interpret the phrases ''standards of performance for any existing source'' and ''the implementation and enforcement of such standards of performance'' to encompass and allow the various components of the portfolio approach. To the extent that a portfolio approach contains measures that are not standards of performance or do not implement or enforce such standards, the EPA is proposing to interpret CAA section 111 as allowing state CAA section 111(d) plans to include measures that are neither standards of performance nor measures that implement or enforce those standards, provided that the measures reduce CO_2 emissions from affected sources. These measures would also be federally enforceable if included in an approved plan.

The EPA's proposed interpretation is based, in part, on CAA section 111(d)'s requirement that states set performance standards ''for'' affected sources. Although ''for'' could be read as meaning that the standards must apply to affected sources, ''for'' is also reasonably interpreted to have a more capacious meaning: Standards (such as EE and RE standards) are reasonably considered to be ''for'' affected sources if they would have an effect on affected sources by, for example, causing reductions in affected EGUs' CO_2 emissions by decreasing the amount of generation needed from affected EGUs. Under this interpretation, and depending on the specific provisions in the state plan, renewable energy and demand-side energy efficiency requirements would be ''for'' fossil fuel-fired EGUs where such standards result in reduced CO_2 emissions from fossil fuel-fired EGUs, even if the standards do not apply directly to fossil fuel-fired EGUs.

The EPA also requests comment on another approach: Whether ''standards of performance for [affected sources]'' is reasonably read to include the emission performance level (i.e., the state goal) on grounds that the level is ''a standard for emissions'' because it is in the nature of a requirement that concerns emissions and it is ''for'' the affected sources because it helps determine their obligations under the plan.

Moreover, where the specific measures in the portfolio approach are not themselves a ''standard of performance,'' state plans may include measures that implement or enforce a standard of performance. For example, if the state's plan achieves the emission performance level through rate-based emission limits applicable to the affected sources, coupled with a crediting mechanism for RE and demand-side EE measures, we propose that RE and demand-side EE measures may be included in the plan as ''implement[ing]'' measures because they facilitate the sources' compliance with their standards of performance. We solicit comment on the extent to which measures such as RE and demand-side EE may be considered ''implement[ing]'' measures in state plans if they are not directly tied to emission reductions that affected sources are required to make through emission limits, and if they are requirements on entities other than the affected sources. In addition, the EPA proposes to interpret CAA section 111(d)(1) to allow state plans to include components of the portfolio approach that are measures that would reduce emissions from affected sources, even if those measures are neither ''standards of performance for existing sources'' nor measures ''for the implementation and enforcement of such standards of performance.'' There is no specific language in CAA section 111(d) or elsewhere in the Act that prohibits states from including measures other than performance standards and implementation and enforcement measures, provided that they reduce emissions from affected EGUs.

This interpretation is consistent with the principle of cooperative federalism, which is one of the foundational principles of the Clean Air Act and which supports providing flexibility to states to meet environmental goals (provided minimum CAA statutory requirements are met). This general principle, especially when combined with the statutory directive that CAA section 111(d) regulations shall establish procedures ''similar to that provided by section 110,'' supports an interpretation of CAA section 111(d) that allows states sufficient flexibility in meeting the state goal set under CAA section 111(d) to include in their CAA section 111(d) plans other measures (i.e., measures that are neither performance standards nor measures that enforce or implement performance standards). The EPA solicits comment on all aspects of its proposed interpretation that states have this flexibility in selecting measures for their state plans under CAA section 111(d).

An alternative interpretation of CAA section 111(d)(1) would suggest that the responsibility to achieve the state's required emission performance level must be assigned solely to affected EGUs. As described elsewhere in this preamble, there are a number of state-level CO_2 programs that take this approach while still taking advantage of low-cost reductions from RE and demand-side EE through the use of complementary measures. This alternative interpretation would be based on, for example: A determination that CAA section 111(d)(1) must be read as precluding a state plan from including measures that are neither standards of performance nor measures for the implementation or enforcement of such standards; an interpretation that the state's obligation to set performance standards ''for'' existing sources means that the standards must apply to affected EGUs and not to other entities; and an interpretation that measures ''for the implementation and enforcement of such performance standards'' do not include measures that are not intended or designed to assist affected EGUs in meeting the performance standards. The EPA requests comment on whether it must adopt this alternative interpretation. If so, the EPA also takes comment on whether there is a way, nonetheless, to allow states to rely on the portfolio approach to some extent and/or for some period of time.

We request comment on all of the interpretations discussed in this section generally, and on all legal issues under CAA section 111(d)(1) with respect to what measures can be included in a state plan and what entities must be legally responsible for meeting those measures.

g. Ongoing Applicability of CAA Section 111(d) State Plan

The EPA is proposing that an existing source that becomes subject to requirements under CAA section 111(d) will continue to be subject to those requirements even after it undertakes a modification or reconstruction. Under this interpretation, a modified or reconstructed source would be subject to both (1) the CAA section 111(d) requirements that it had previously been subject to and (2) the modified source or reconstructed source standard being promulgated under CAA section 111(b) simultaneously with this rulemaking. It should be noted that this proposal applies to any existing source subject to any CAA section 111(d) plan, and not only existing sources subject to the CAA section 111(d) plans promulgated under this rulemaking.

As noted above, a ''new source'' is defined under CAA section 111(a)(2) as ''any stationary source, the construction or modification of which is commenced after,'' in general, a proposed or final CAA section 111(b) rule becomes applicable to that source; and under

[275] *Chevron U.S.A., Inc.* v. *NRDC,* 467 U.S. 837, 842–44 (1984).

section 111(a)(6), an ''existing source'' is defined as ''any stationary source other than a new source.'' Under these definitions, an ''existing source'' that commences construction of a modification or reconstruction after the EPA has proposed or finalized a CAA section 111(b) standard of performance applicable to it, becomes a ''new source.'' However, CAA section 111(d) is silent on whether requirements imposed under a CAA section 111(d) plan continue for a source that ceases to be an existing source because it modifies or reconstructs. Specifically, CAA section 111(d)(1) provides that ''each State shall submit to the Administrator a state plan which (A) ''establishes standards of performance for any existing source'' but does not say whether, once the EPA has approved a state plan that establishes a standard of performance for a given source, that standard is lifted if the source ceases to be an existing source. Similarly, no other provisions of CAA section 111 address whether the imposition of a CAA section 111(b) standard on a modified or reconstructed source ends the source's obligation to meet any applicable CAA section 111(d) requirements.

Because CAA section 111(d) does not address whether an existing source that is subject to a CAA section 111(d) program remains subject to that program even after it modifies or reconstructs, the EPA has authority to provide a reasonable interpretation, under the Supreme Court's decision in *Chevron U.S.A. Inc.* v. *NRDC,* 467 U.S. 837, 842–844 (1984). The EPA's interpretation is that under these circumstances, the source remains subject to the CAA section 111(d) plan, for two reasons. The first is to assure the integrity of the CAA section 111(d) plan. The EPA believes that many states will develop integrated plans that include all of their EGUs, such as rate- or mass-based trading programs. Uncertainty about whether units would remain in the program could be very disruptive to the operation of the program. The second reason is to avoid creating incentives for sources to seek to avoid their obligations under a CAA section 111(d) plan by undertaking modifications. The EPA is concerned that owners or operators of units might have incentives to modify purely because of potential discrepancies in the stringency of the two programs, which would undermine the emission reduction goals of CAA section 111(d).

The EPA invites comments on this interpretation of CAA section 111(d)(1), including whether this interpretation is supported by the statutory text and whether this interpretation is sensible policy and will further the goals of the statute. It should be noted that this interpretation is severable from the rest of this rulemaking, so that if the EPA revises this interpretation in the final rule or if the EPA adopts this interpretation in the final rule but it is invalidated by a Court, there would be no effect on the rest of this rulemaking.

2. Timing for Implementation and Achievement of Goals

This section describes proposed state plan requirements related to the timing of achieving emission performance goals, including performance demonstrations, performance periods, and interim progress milestones.

As previously discussed, the goals are derived from application of four ''building blocks.'' The EPA has based the application of some of these measures to reduce CO_2 emissions, particularly blocks 3 (expansion of cleaner generating capacity) and 4 (increasing demand-side energy efficiency), on forward-looking, longer-term assumptions. For example, the EPA expects technologies to reduce carbon emissions to more fully develop over time and acknowledges the cumulative effects of implementation of EE programs and addition of RE generating capacity over time. Therefore, the EPA is not proposing to require each state to meet its full, final goal immediately, but rather to meet it by 2030. The EPA realizes, however, that states can achieve emission reductions from those and other measures in the short-term. Therefore, the EPA is proposing that states begin meeting interim goals, beginning in 2020. The EPA also believes that timing flexibility in implementing measures provides significant benefits that allow states to develop plans that will help states achieve a number of goals, including: Reducing cost, addressing reliability concerns, and addressing concerns about stranded assets. Therefore, the EPA is also proposing to allow states flexibility to define the trajectory of emission performance between 2020 and 2029, as long as the interim emission performance level is met on a 10-year average or cumulative basis and the 2030 emission performance level is achieved.

Section VIII.B.1.a of this preamble provides an overview of the proposals for state plan performance demonstrations and timing of emission reductions. Subsequent subsections include proposals for the start date for the interim goal performance period, the duration of the performance periods for the final and interim goals, interim progress milestone requirements, consequences if actual emission performance does not meet the state goal, and out-year requirements for states to maintain CO_2 emission performance levels over time consistent with the final goal. In Section VIII.B.2.f of this preamble, the agency also requests comment on alternative requirements aimed at continued emission performance improvement after 2029. In Section VIII.B.2.g of this preamble, the EPA proposes flexibility for states to change from mass-based to rate-based goals in different performance periods and, in Section VIII.B.2.h, we solicit comment on planning requirements that match the option of alternative, less stringent state goals.

a. Performance Demonstrations and Timing of Emission Reductions

As described previously, the agency is proposing final state-specific goals (specified in Table 8) that represent emission rates to be achieved by 2030, as well as interim goals, to be achieved on average over the 10-year period from 2020–2029. The agency is also proposing that emission performance levels consistent with the final state-specific goals be maintained after 2030.

This relatively long planning and implementation period provides states with substantial flexibility regarding methods and timing of achieving emission reductions. States may wish to make adjustments to their implementation approaches along the way, or as conditions change may need to make adjustments to ensure that their plans achieve the goals as intended. As a result, the agency envisions that the EPA, states, and affected entities will have an ongoing relationship in the course of implementing this program.

The EPA proposes that a state plan must demonstrate projected achievement of the emission performance levels in the plan, and these emission performance levels must be equivalent to or better than the interim and final goals established by the EPA. Specifically, the state plan must demonstrate that the projected emission performance of affected EGUs in the state will be equivalent to or better than the applicable interim goal during the 2020–2029 period, and equivalent to or better than the applicable final goal during the year 2030. The state plan must identify requirements that continue to apply after 2030 and are likely to maintain continued emission performance by affected EGUs that meets the final goal; however, quantitative projections of emission performance by affected EGUs

beyond 2030 would not be required by this rule under the proposed approach. Instead, the EPA proposes that the state plan would be considered to provide for maintenance of emission performance consistent with the final goal if the plan measures used to demonstrate achievement of the final goal by 2030 will continue in force and not sunset.

In addition to demonstrating that projected plan performance will meet the interim and final state goals, the EPA proposes that state plans must contain requirements for tracking actual plan performance during implementation. For plans that do not include enforceable requirements for affected EGUs that ensure achievement of the full level of required emission performance and interim progress, the state plans would be required to include periodic program implementation milestones and emission performance checks, and include corrective measures to be implemented if mid-course corrections are necessary. The state plan would provide for continued tracking of emission performance after 2030, and for corrective measures if the emission performance of affected EGUs in the state did not continue to meet the 2030 final goal during any three-year performance period.

The rationale for this approach is that it would ensure that states design their plans in a way that considers both the interim and final goals. If only the interim goal were considered, a state plan might not be sufficient to achieve the final goal.[276]

The agency requests comment on a second option in which, in addition to submitting a plan demonstrating emission performance through 2030, states would be required to make a second submittal in 2025 showing whether their plan measures would maintain the final-goal level of emission performance over time (as further described below). If not, the state submittal would be required to strengthen or add to measures in the state plan to the extent necessary to maintain that level of performance over time.

The EPA also requests comment on whether 2025, or an earlier or later year, would be the optimal year for a second plan submittal under the second option.

b. Start Date for Performance Period for Interim Goal

A performance period is a period for which the state plan must demonstrate that the required emission performance level will be met. The EPA proposes a start date of January 1, 2020, for the interim goal plan performance period.[277] This date would be the beginning of the 10-year period for which a state must demonstrate that the projected emission performance level of affected EGUs in the state, on average, will be equivalent to or better than the applicable interim goal. The agency generally requests comment on the appropriate start date and rationale.

In considering the start date, it is relevant to consider the due dates for state plan submittals and the amount of time available for program implementation by the start date. January 2020 is 3.5 years from the proposed June 2016 deadline for initial plan submittals, 2.5 years from the proposed June 2017 extended deadline for complete plans from states not participating in a multi-state plan, and 1.5 years from the proposed June 2018 extended deadline for complete plans from states participating in a multi-state plan. The EPA suggests that affected entities may have greater lead time for compliance than might be implied by the plan submittal dates referenced above. Affected entities will have knowledge of state requirements as they are adopted, and the state must adopt rules and requirements in advance of submitting its complete plan to the EPA. Also, as explained in detail in subsection c, states may choose a different emission performance improvement trajectory from that which the EPA assumes for purposes of calculating state goals, achieving lesser levels of performance in early years and more in later years, provided, of course, that the interim 10-year average requirement is met.

The EPA proposes that a 2020 start date for the interim goal plan performance period is achievable in light of the following additional considerations. First, existing state programs will play a role in helping to achieve this rule's proposed emission performance levels. Second, in advance of this proposal, many states already were contemplating design of strategies that would achieve CO_2 emission reductions equivalent to those that could be required by CAA section 111(d) emission guidelines. Third, for inclusion in the building blocks, the EPA considered only those emission abatement measures that are technically feasible and broadly applicable, and can provide reductions in CO_2 emissions from affected EGUs at reasonable cost.

For example, the EPA expects that many EGUs will meet their requirements in part by implementing heat rate improvements, and those actions may be undertaken promptly. The plant operations and maintenance (O&M) and engineering solutions used to improve heat rates at existing EGUs have long been commercially available and have been implemented at EGUs for many years. Further, the relatively modest capital costs (average $100/kW) and significant fuel savings associated with a suite of heat rate improvement (HRI) methods result in this measure being a low-cost approach to reducing CO_2 emissions from existing EGUs. HRI ''best practices'' (e.g., installation of modern control systems, operator training, smart soot blowing) are the least-cost HRI methods and can be applied quickly, without lengthy EGU outages. The somewhat more costly HRI ''upgrades'' (e.g., steam turbine upgrade, boiler draft fan/driver upgrade) may require modest EGU outages to implement, but have also been applied on numerous EGUs to improve or maintain performance. Drawing on the power sector's extensive experience with HRI methods, and the many existing supply chains already supporting these methods, the EPA expects that it would be feasible to implement HRI projects (i.e., building block 1) by 2020.

Dispatch changes, which are largely driven by the variable cost of operating a given EGU, occur on an hourly basis in the power sector. The average availability factor for NGCCs in the U.S. generally exceeds 85 percent, and can exceed 90 percent for selected groups.[278] In addition, the existing natural gas pipeline and electricity transmission networks are already connected to every existing NGCC facility, and can support aggregate operation of the NGCC fleet at 70 percent (or above) at the state level, or can be reasonably expected to do so in the time frame for compliance with this rule. Therefore, building block 2, which represents shifting of generation from steam fossil EGUs to existing NGCCs, is a viable method for providing CO_2

[276] The 2020–2029 interim goal is expressed as a 10-year average emission rate to provide states with flexibility in designing their plans. Due to the potential for continued end-use energy efficiency improvements, the 2029 four-building-block BSER-based level is a more stringent level than the 2020–2029 average four-building-block BSER-based level. The purpose of the final goal is to ensure that each state ultimately achieves the emission performance level for affected EGUs that is achievable by 2029. Without the final goal, it is possible that a state could achieve the 2020–2029 interim goal but not achieve the 2030 final goal.

[277] The start date for a plan performance period must match the start date of the corresponding state emission performance goal. If a start date other than January 2020 were selected, the EPA would recompute the state goals consistent with the selected start date.

[278] Source: NERC, 2008–2012 Generating Unit Statistical Brochure.

emission reductions at existing EGUs by the 2020 compliance start date.

Building Block 3 is based on shifting generation from affected fossil units to new renewable energy generating capacity, which is added over time, and new or preserved nuclear capacity, all of which is expected to be in place by 2020 (see the GHG Abatement Measures TSD for more information).

Finally, there is considerable experience with the states and the power sector in designing and implementing demand-side energy efficiency improvement strategies and programs. It is also well accepted that such improvements can achieve reductions in CO_2 emissions from existing EGUs at a reasonable cost. Building block 4 represents a feasible pathway for reducing utilization of carbon-emitting EGUs by implementing improvements in demand-side energy efficiency. This building block is based on a ''best practices'' scenario where all states achieve a level of performance—matching a level achieved or committed to by twelve leading states—of 1.5 percent annual incremental electricity savings as a percentage of retail sales. For the best practices scenario, all states achieve this level of performance no later than 2025, with leading states reaching this level sooner. Each state's current level of performance is taken into account, with states achieving lower levels of performance being allowed more time to reach the best practice level.

c. Duration of Performance Periods for Final and Interim Goals

The EPA recognizes that a state's circumstances and choice of emission reduction strategies may affect the timing of CO_2 emission performance improvement within a multi-year planning period. States can be expected to select various combinations of measures and those measures may vary in the time needed to reach full implementation. The agency recognizes that certain emission reduction measures and programs (e.g., heat rate improvements) are generally easier to implement in the near term, while others (e.g., renewable portfolio standards, demand-side energy efficiency programs) may require several years to implement because of the time necessary to establish the proper infrastructure if a state does not already have such programs in place. Though some states have already implemented such programs that are achieving results, other states may have to establish them for the first time. New single and multi-state programs, as well as existing single and multi-state programs that are adding or revising measures, may need time for implementation to achieve the required level of emission performance.

As described in Section VII of the preamble, the EPA is proposing state-specific CO_2 emission performance goals in a multi-year format to provide states with flexibility for the timing of programs and measures that improve EGU emission performance, while ensuring an overall level of performance consistent with application of the BSER. Specifically, the agency is proposing the state-specific goals (shown in Table 8) which represent emission rates to be achieved by 2030 (final goal) and emission rates to be achieved on average over the 2020–2029 period (the interim goal).

The EPA proposes the following as the preferred option for the final and interim goal performance periods. As further explained below, this option reflects three main objectives: (1) Provide states with timing flexibility during the interim goal period to accommodate differences in state adoption processes and types of state programs, (2) ensure that state plans are designed to achieve the final goal no later than 2030, and (3) provide flexibility for year-to-year variation in actual emission performance that may occur as the electricity system responds to economic fluctuations.

Interim goal—Projected plan performance demonstration: To be approvable, a state plan must demonstrate that the emission performance of affected EGUs will meet the interim emission performance level on average over the 2020–2029 period.

Interim goal—Actual plan performance check: In 2030, the emission performance of affected EGUs during the period 2020–2029 must be compared against the interim goal. (In addition, as described separately below, interim emission performance checks will occur during this 10-year period.)

Final goal—Projected plan performance demonstration: To be approvable, a state plan must demonstrate that the emission performance of affected EGUs will meet the final emission performance level no later than 2030, on a single-year basis.

Final goal—Actual plan performance check: Starting at the end of 2032, emission performance of affected EGUs must be compared against the final goal on a three-year rolling average basis (i.e., 2030–32, 2031–33, 2032–2034, etc.).

This proposed approach provides a 10-year performance period for the interim performance level. The 10-year period allows states flexibility for timing of program implementation as the state ramps up its programs to achieve the final performance level. Using the single year 2030 as the projected year for achievement of the final goal ensures that state plans are designed to achieve the final goal no later than 2030; providing a multi-year time frame for projected plan performance would inappropriately delay the requirement for a final-goal level of performance that the EPA's analysis shows is achievable at the end of the 10-year interim ramp-up period. Using 2030 also avoids overlap with the interim goal performance period. The rolling three-year performance periods for measuring actual plan performance against the final goal performance level are proposed in light of year-to-year variability in economic and other factors, such as weather, that influence power system operation and affect EGU CO_2 emissions. The choice of 2030–2032 avoids overlap with the 2020–2029 interim goal performance period.

For a rate-based plan, 2020–2029 emission performance is an average CO_2 emission rate for affected EGUs representing cumulative CO_2 emissions for affected EGUs over the course of the 10-year performance period divided by cumulative MWh energy output [279] from affected EGUs over the 10-year performance period, with rate adjustments for qualifying measures, such as end-use energy efficiency and renewable energy measures, as described in Section VIII.F.3. For a mass-based plan, 2020–2029 emission performance is total tons of CO_2 emitted by affected EGUs over the 10-year performance period.

The agency invites comment on this and other approaches to specifying performance periods for state plans.

d. Program Implementation Milestones and Tracking of Emission Performance

The EPA recognizes the importance of ensuring that, during the proposed 10-year performance period (2020–2029) for the interim goal, a state is making steady progress toward achieving the required level of emission performance. The EPA is proposing that certain types of state plans be required to have program implementation milestones to ensure interim progress, as well as periodic checks on overall emission performance leading to corrective measures if necessary.

Some types of plans are ''self-correcting'' in that they inherently

[279] For EGUs that produce both electric energy output and other useful energy output, there would also be a credit for non-electric output, expressed in MWh.

would assure interim performance and full achievement of the state plan's required level of emission performance through requirements that are enforceable against affected EGUs. One example is a state plan with a rate-based emission performance level that requires affected EGUs collectively to meet an emission rate consistent with the state's required emission performance level, and allows EGUs to comply through an emission rate averaging system. Another example is a plan that includes measures or actions (e.g., emission limits that apply to affected EGUs and ensure full plan performance) that take effect automatically if the plan's required emission performance level is not met, in accordance with a specified milestone. The EPA requests comment on whether there are other types of state plans that should be considered ''self-correcting.''

The EPA proposes that self-correcting plans need not contain interim milestones consisting of program implementation steps, because these state plans inherently require both interim progress and achievement of the full level of required emission performance in a manner that is federally enforceable against affected EGUs. Annual reporting of emission performance by the state, however, is required for all types of plans.

For plans that are not self-correcting, the EPA proposes that the state plan must identify periodic program implementation milestones (e.g., start of an end-use energy efficiency program, retirement of an affected EGU, or increase in portfolio requirements under a renewable portfolio standard) that are appropriate to the programs and measures included in the plan. If, during plan implementation, a state were to miss program implementation milestones in its plan, it would need to report the delay to the EPA, explain the cause, and describe the steps the state will take to accelerate subsequent implementation to achieve the planned improvements in emission performance. Depending on the severity of delay and the explanation, the EPA could ultimately evaluate actions under CAA authorities to ensure timely program implementation.

In addition, we propose that the state and the EPA would track state plan emission performance on an ongoing basis, with states reporting performance data to the EPA annually by July 1. During the interim performance period, beginning in 2022, the state would be required each year to include a comparison of emission performance achieved to performance projected in the state plan. Each comparison would cover the preceding two-year period. The EPA may also approve regular, periodic emission comparison checks with a different frequency or comparison period to reflect the design of a state's programs (e.g., compliance periods for EGUs under an emission limit).

A report and corrective measures would be required if an interim emission check showed that actual emission performance of affected entities was not within 10 percent of the performance projected in the state plan (i.e., for a rate-based plan, if the average emission rate of affected EGUs were 10 percent higher than plan projections, or for a mass-based plan, if collective emissions of affected EGUs were 10 percent higher than plan projections). In that event, the state would be required in its submission to explain reasons for the deviation (e.g., energy efficiency program not working as effectively as expected, prolonged extreme weather that had been unanticipated in electricity demand projections) and specify the corrective measures that will be taken to ensure that the required level of emission performance in the plan will be met. The state also would be required to implement those corrective measures as expeditiously as practical.

The agency proposes that states be given a choice regarding when to adopt into regulation the corrective measures that the state plan identifies for implementation in the event that state plan performance is deficient. First, the state could adopt corrective measures into regulation prior to plan submittal in a manner that enables the state to implement the measures administratively, without further legislation or rulemaking, if a performance deficiency occurs during plan implementation. This would expedite implementation of corrective measures once a deficiency is discovered. Second, the state could elect to wait to adopt into regulation the corrective measures identified in the plan until after a plan performance deficiency is discovered. The EPA proposes this choice in recognition of the fact that it may be challenging for states to fully adopt corrective measures in advance to address the possibility that their plan will not perform as projected. However, if a state makes the latter choice, the EPA proposes that the state must report the reasons for deficient performance and must implement corrective measures if actual emission performance was inferior to projected performance by eight percent or more (rather than 10 percent or more). The reason for the lower percentage trigger is to identify a gradually developing deficiency in plan performance earlier in time. Legislative and/or regulatory action to adopt corrective measures after a deficiency is discovered will take significant time. State processes to activate corrective measures should be triggered earlier if corrective measures are not adopted in regulation and ready to implement.

The EPA alternatively requests comment on whether states should be required to create legal authority and/or adopt regulations providing for corrective measures in developing the state plan. The agency requests comment generally on the conditions that should trigger corrective measure requirements. The agency also solicits comment on whether actual emission performance inferior to projected performance by ten percent (for plans with corrective measures adopted into regulation prior to complete plan submittal) is the appropriate trigger for requiring a state to report the reasons for deficient performance and to implement corrective measures. We are also soliciting comment on the range of five percent to fifteen percent. For plans without corrective measures adopted into regulation prior to complete plan submittal, the agency solicits comment on whether the proposed eight percent emission performance deviation trigger is appropriate. We also solicit comment on the range of five percent to ten percent.

The EPA proposes that the state will be required to compare actual emission performance achieved during the entire 10-year interim performance period (i.e., 2020–2029) against the interim goal. As noted above, beginning after 2032, the EPA proposes that the state be required to compare actual emission performance achieved against the final goal on a rolling three-year average basis (e.g., 2030–32, 2031–33, etc.). The EPA also requests comment on the milestone approach and emission performance checks outlined above in the context of the alternative 5-year performance period and the planning approach for alternative state goals, which is described below.

e. Consequences if Actual Emission Performance Does Not Meet State Goal

There are scenarios under which an approved state plan might fail to achieve a level of emission performance by affected EGUs that meets the state goal. Under some types of plans, a possible scenario is that despite successful plan implementation, emissions under the plan turn out to be higher than projected at the time of plan

approval because actual economic conditions vary from economic assumptions used when projecting emission performance. State officials have raised the possibility that achieved emission performance might not meet projected performance if, for example, planned retirements of EGUs were postponed because severe weather produced greater-than-expected electricity generation needs. In addition, emissions could theoretically exceed projections because affected entities under a state plan did not fulfill their responsibilities, or because the state did not fulfill its responsibilities.

The EPA believes that the emission guidelines should specify the consequences in the event that actual emission performance under a state plan does not meet the applicable interim goal in 2020–2029, or does not meet the applicable final goal in 2030–2032 or later, because CAA section 111(d) is not specific on this point. The agency requests comment on how the consequences should vary depending on the reasons for a deficiency in performance.

Specifically, the agency requests comment on whether consequences should include the triggering of corrective measures in the state plan, or plan revisions to adjust requirements or add new measures. The agency also requests comment on whether corrective measures, in addition to ensuring future achievement of the state goal, should be required to achieve additional emission reductions to offset any emission performance deficiency that occurred during a performance period for the interim or final goal. This concept has been applied, for example, in the Acid Rain Program under Title IV of the CAA; a source that has sulfur dioxide emissions exceeding the emission allowances that it holds at the end of the period for demonstrating compliance is required subsequently to obtain additional emission reductions to offset its excess emissions.[280] The agency also requests comment on the process for invoking requirements for implementation of corrective measures in response to a state plan performance deficiency.

The EPA further requests comment on whether the agency should promulgate a mechanism under CAA section 111(d) similar to the SIP call mechanism in CAA section 110. Under this approach, after the agency makes a finding of the plan's failure to achieve the state goal during a performance period, the EPA would require the state to cure the deficiency with a new plan within a specified period of time (e.g., 18 months). If the state still lacked an approved plan by the end of that time period, the EPA would have the authority to promulgate a federal plan under CAA section 111(d)(2)(A).

f. Out-Year Requirements: Maintaining or Improving the Level of Emission Performance Required by the Final Goal

The agency is determining state goals for affected EGU emission performance based on application of the BSER during specified time periods. This raises the question of whether affected EGU emission performance should only be maintained—or instead should be further improved—once the final goal is met in 2030. This involves questions of goal-setting as well as questions about state planning. In this section, the EPA proposes that a state must maintain the required level of performance, and requests comment on the alternative of requiring continued improvement.

The EPA believes that Congress either intended the emission performance improvements required under CAA section 111(d) to be permanent or, through silence, authorized the EPA to reasonably require permanence. Other CAA section 111(d) emission guidelines set emission limits to be met permanently. Therefore, the EPA is proposing that the level of emission performance for affected EGUs represented by the final goal should continue to be maintained in the years after 2030. The EPA is proposing a mechanism for implementing this objective, and is taking comment on an alternative option.

As noted above, the EPA proposes that the state plan must demonstrate that plan measures are projected to achieve the final emission performance level by 2030. In addition, the state plan must identify requirements that continue to apply after 2030 and are likely to maintain affected EGU emission performance meeting the final goal; however, quantitative projections of emission performance beyond 2030 would not be required under the proposed option. Instead, the EPA proposes that the state plan would be considered to provide for maintenance of emission performance consistent with the final goal if the plan measures used to demonstrate projected achievement of the final goal by 2030 will continue in force and not sunset.[281] After implementation, the state would be required to compare actual plan performance against the final goal on a rolling three-year average basis starting in 2030, and to implement corrective measures if necessary.

The EPA also requests comment on an alternative approach to a state's pre-implementation demonstration that the final-goal level of performance will be maintained after 2030. Under this alternative, the state plan would be required to include projections demonstrating that emission performance would continue to meet the final goal for up to 10 years beyond 2030. This approach could be implemented through a second round of state plan analysis and submittals in 2025 to make the demonstration and strengthen or add measures if necessary. The EPA generally requests comment on appropriate requirements to maintain the emission performance of affected EGUs in years after 2030.

The EPA also requests comment on whether we should establish BSER-based state emission performance goals for affected EGUs that extend further into the future (e.g., beyond the proposed planning period), and if so, what those levels of improved performance should be. Under this alternative, the EPA would apply its goal-setting methodology based on application of the BSER in 2030 and beyond to a specified time period and final date. The agency requests comment on the appropriate time period(s) and final year for the EPA's calculation of state goals that reflect application of the BSER under this approach.

The EPA notes that CAA section 111(b)(1)(B) calls for the EPA, at least every eight years, to review and, if appropriate, revise federal standards of performance for new sources. This requirement provides for regular updating of performance standards as technical advances provide technologies that are cleaner or less costly. The agency requests comment on the implications of this concept, if any, for CAA section 111(d).

g. State Flexibility To Choose Mass-Based and Rate-Based Goals After 2029

The EPA proposes that states have flexibility to choose between a rate-

[280] CAA section 411(b).

[281] This is straightforward for plans with EGU emission limits that ensure the full level of performance required. For renewable energy programs, the agency suggests that the state could continue to require the renewable portfolio percentage level that was relied upon to demonstrate projected achievement of the final goal performance level in 2030. For plans that rely in part on end-use energy efficiency programs and measures, the EPA requests comment on what a state would need to require in its plan to show that performance will be maintained after 2030. End-use energy efficiency programs and measures often involve an annual energy savings requirement or goal, and some types require additional monetary expenditures each year to meet those savings requirements or goals.

based and mass-based performance level for each performance period. For example, if a state plan used a mass-based performance level for the 2020–2029 period, the state plan may still use a rate-based performance level for final goal performance periods, or vice versa.

A state that adopted a mass-based performance level for 2020–2029 would have two options for addressing any perceived need for emissions flexibility in light of anticipated electricity demand growth after 2029. The state either could adopt a rate-based performance level consistent with the final goal, or could adopt a mass-based performance level based on a translation of the rate-based final goal to a mass-based goal.

h. Planning Approach for Alternative State Goals

In Section VII, the EPA requests comment on alternative, five-year state emission performance goals for affected EGUs shown in Table 9. The alternative goals represent emission rates achievable on average during the 2020–2024 period, as well as emission rates to be achieved and maintained after 2024. These alternative goals are less stringent than the proposed goals in Table 8.

To accompany the alternative goals, the EPA requests comment on another approach for state plan performance periods. This approach would require state plans to demonstrate that the required interim emission performance level will be met on average by affected EGUs during the five-year 2020–2024 interim period, and that the alternative final goal be met no later than 2025. After plan implementation, actual emission performance would be compared with the alternative final goal on a three-year rolling average basis, starting with 2025–2027, in light of year-to-year variability in economic and other factors, such as weather, that influence power system operation and affect EGU CO_2 emissions.

In connection with the alternative state goals, for the years after 2027, the EPA requests comment on the same ''out-year'' issues and concepts for maintaining or improving emission performance over time that are described above in Section VIII.B.2.f. The EPA requests comment on whether a state plan should provide for emission performance after 2025 solely through post-implementation emission checks that do not require a second plan submittal, or whether a state should also be required to make a second submittal prior to 2025 to demonstrate that its programs and measures are sufficient to maintain performance meeting the final goal for at least 10 years. In addition, the agency requests comment on the appropriate date for any second state plan submittal designed to maintain emission performance after the 2025 performance level is achieved.

C. Criteria for Approving State Plans

The EPA is proposing to require the twelve plan components discussed in Section VIII.D of this preamble. We will evaluate the sufficiency of each plan based on the plan addressing those components and on four general criteria for a state plan to be approvable. The EPA proposes to use the combination of these twelve plan components and four general criteria to determine whether a state's plan is ''satisfactory'' under CAA section 111(d)(2)(A). First, a state plan must contain enforceable measures that reduce EGU CO_2 emissions. Second, these enforceable measures must be projected to achieve emission performance equivalent to or better than the applicable state-specific CO_2 goal on a timeline equivalent to that in the emission guidelines.[282] Third, EGU CO_2 emission performance under the state plan must be quantifiable and verifiable. Fourth, the state plan must include a process for state reporting of plan implementation (at the level of the affected entity), CO_2 emission performance outcomes, and implementation of corrective measures, if necessary. The EPA requests comments on all aspects of these general criteria and the twelve specific plan components described below.

The agency also notes that a CAA section 111(d) state plan is not a CAA section 110 state implementation plan (SIP). Although there are similarities in the two programs, approvability criteria for CAA section 111(d) plans need not be identical to approvability criteria for SIPs.

1. Enforceable Measures

In developing its plan, a state must ensure that the plan is enforceable and in conformance with the CAA. We are seeking comment on the appropriateness of existing EPA guidance on enforceability in the context of state plans under CAA section 111(d), considering the types of affected entities that might be included in a state plan.[283] This guidance serves as the foundation for the types of emission limits that the EPA has found can be enforced as a practical matter and sets forth the general principle that a requirement that is enforceable as a practical matter is one that is quantifiable, verifiable, straightforward, and calculated over as short a term as reasonable.

As discussed in section VIII.F.1, the EPA is seeking comment on whether the agency should provide guidance on enforceability considerations related to requirements in a state plan for entities other than affected EGUs (and if so, which types of entities). Also, as discussed in section VIII.F.4, the EPA intends to develop guidance for evaluation, monitoring, and verification (EM&V) of renewable energy and demand-side energy efficiency programs and measures incorporated in state plans.

A state plan must include enforceable CO_2 emission limits (either rate-based or mass-based) that apply to affected EGUs. As noted above, the EPA is proposing that a state plan may take a portfolio approach, which would include enforceable CO_2 emission limits that apply to affected EGUs as well as other enforceable measures, such as RE and demand-side EE measures, that avoid EGU CO_2 emissions and are implemented by the state or by another entity assigned responsibility by the state. As noted above, we are proposing that state plans are not required to impose emission limits on affected EGUs that in themselves fully achieve the emission performance level. However, we are seeking comment on whether, for state plans where emission limits applicable to affected EGUs alone would not assure full achievement of the required level of emission performance, the state plan must include additional measures that would apply if any of the other portfolio of measures in the plan are not fully implemented, or if they are, but the plan fails to achieve the required level of emission performance.[284]

The EPA recognizes that a portfolio approach may result in enforceable state plan obligations accruing to a diverse range of affected entities beyond affected EGUs, and that there may be challenges to practically enforcing against some such entities in the event of noncompliance. We request comment

[282] Flexibilities provided to states in meeting this general approvability criterion are discussed below in Section VIII.C.2., emission performance.

[283] Enforceability guidance includes:(1) September 23, 1987 memorandum and accompanying implementing guidance, ''Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency,'' (2) August 5, 2004 ''Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures,'' and (3) July 2012 ''Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F.''

[284] This could include, for example, an expansion of the scope or an increase in stringency of the current measures in the plan, a second set of measures that avoid EGU CO_2 emissions, or emissions limits that apply to affected EGUs.

on all aspects associated with enforceability of a state plan and how to ensure compliance. We are also seeking comment on enforceability considerations under different state plan approaches, which is addressed below in VIII.F.1.

2. Emission Performance

The second criterion for approvability is that the projected CO_2 emission performance by affected EGUs (taking into account the impacts of plan measures that are associated with reducing utilization from affected EGUs) must be equivalent to, or better than, the required CO_2 emission performance level in the state plan. State plans that are projected to achieve an average CO_2 emission rate (expressed in lb CO_2/MWh) or tonnage CO_2 emission outcome by all affected EGUs equal to, or lower than, the required level of CO_2 emission performance in the plan would meet this approvability criterion.

We are proposing that states may demonstrate such emission performance by affected EGUs either on an individual state basis or jointly on a multi-state basis.

All of the emission reduction measures included in the agency's determination of the BSER reduce CO_2 emissions from affected EGUs. As a result, the EPA is not proposing that out-of-sector GHG offsets could be applied to demonstrate CO_2 emission performance by affected EGUs in a state plan.

However, emission limits for affected EGUs that are included in state plans could still include provisions that provide the ability to use GHG offsets for compliance with the emission limits, provided those emission limits would achieve the required level of emission performance for affected EGUs. We note that inclusion of such provisions would create a degree of uncertainty about the level of emission performance that would be achieved by affected EGUs when complying with the emission limit (as potentially would other flexibility mechanisms included in an emission limit). As a result, such emission limits would not be considered ''self-correcting'' as discussed above at Section VIII.B.2.d.

All existing state emission budget trading programs addressing GHG emissions include out-of-sector, project-based emission offsets, which may be used to cover a portion of the compliance obligation of affected sources. Other states may want to take a similar approach, for example, to incentivize GHG emission reductions from land use and agricultural waste management. How to address GHG offsets included in EGU emission limits when projecting emission performance under a state plan is addressed in the Projecting EGU CO_2 Emission Performance in State Plans TSD.

The ISO/RTO Council, an organization of electric grid operators, has suggested that ISOs and RTOs could play a facilitative role in developing and implementing region-wide, multi-state plans, or coordinated individual state plans. Existing ISOs and RTOs could provide a structure for achieving efficiencies by coordinating the state plan approaches applied throughout a grid region. Just as the ISO/RTO regions today share the benefits and costs of efficient EGU dispatch across state boundaries, there are significant efficiencies that could be captured by coordinating individual state plans or implementing multi-state plans within a grid region. Under one variant of this approach, states would implement a multi-state plan and jointly demonstrate CO_2 emission performance by affected EGUs across the entire ISO/RTO footprint. States with borders that cross the boundary of one or more ISO or RTO footprints would need to include multiple plan components that address affected EGUs in each respective ISO or RTO. The EPA is seeking comment on this idea. States that are outside the footprint of an ISO or RTO may benefit from consulting with other relevant planning authorities when preparing state plans. We are also requesting comment on this idea.

3. Quantifiable and Verifiable Emission Performance

The third criterion for approvability is that a state plan specify how the effects of each state plan measure will be quantified and verified. The EPA proposes that all plans must specify how CO_2 emissions from affected EGUs are monitored and reported. The EPA is proposing that both mass-based and rate-based plans must include CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs, as specified in the emission guidelines. A rate-based plan must also include monitoring, reporting, and recordkeeping requirements for useful energy output from affected EGUs (electricity and useful thermal output), as specified in the emission guidelines. With one exception, these proposed requirements are consistent with those in the proposed EGU Carbon Pollution Standards for New Power Plants. See 79 FR 1430–1519 (January 8, 2014). The exception is that we are proposing that useful energy output be measured in terms of net output rather than gross output, as discussed below.

For state plans that include other measures that avoid EGU CO_2 emissions, such as RE and demand-side EE measures, the state will also need to include quantification, monitoring, and verification provisions in its plan for these measures, which may vary depending on the types of requirements included in the specific plan, as specified in the emission guidelines. This may include, for example, quantification, monitoring, and verification of RE generation and demand-side EE energy savings under a rate-based approach.[285]

4. Reporting and Corrective Actions

The fourth criterion for approval is that a state plan must (i) specify a process for annual reporting to the EPA of overall plan performance and implementation (including compliance of affected entities with applicable emission standards) during the plan performance periods, and (ii) include a process and schedule for implementing corrective measures if reporting shows that the plan is not achieving the projected level of emission performance. We solicit comment on whether the latter process should include the adoption of new plan measures and subsequent resubmission of the plan to the EPA for review and approval, or whether the process should specify the implementation of measures that are already included in the approved plan in the event that the projected level of performance is not being achieved. We also solicit comment on the point at which such a process and schedule would be triggered, such as at the end of a multi-year plan performance period if emission performance is not met, or at specified interim stages within a multi-year plan performance period. For plans with self-correcting mechanisms, the agency is not proposing that requirements for corrective measures be included in the plan. All of these considerations are addressed in more detail above in Section VIII.B.2.

The agency is also proposing that a state plan specify appropriate periodic reporting requirements for each affected entity in a state plan that will be reported at least annually, electronically, and disclosed on a state database accessible by the public and the EPA. The EPA is requesting comment on the appropriate scope of these reporting requirements and whether the reports should also be directly submitted by the affected

[285] Considerations for quantification, monitoring, and verification of RE and demand-side EE measures are addressed in Section VII.F.4 of this preamble and in the State Plan Considerations TSD.

entities to the EPA, as well as to the state.

D. State Plan Components

The EPA is proposing that an approvable plan must meet the approvability criteria described above and include the twelve state plan components summarized below, consistent with additional specific requirements explained elsewhere in this notice. Plans must comply with the EPA framework regulations at 40 CFR 60.23–60.29, except as specified otherwise by these emission guidelines. These requirements apply both to individual state plans and multi-state plans.

For states wishing to participate in a multi-state plan, the EPA is proposing that only one multi-state plan would be submitted on behalf of all participating states. The joint submittal would be signed by authorized officials for each of the states participating in the multi-state plan and would have the same legal effect as an individual submittal for each participating state. The joint submittal would adequately address plan components that apply jointly for all participating states and for each individual state in the multi-state plan, including necessary state legal authority to implement the plan, such as state regulations and statutes. Because the multi-state plan functions as a single plan, each of the required plan components described below (e.g., plan performance levels, program implementation milestones, emission performance checks, and reporting) would be designed and implemented by the participating states on a multi-state basis.

We are also seeking comment on two additional options for multi-state plan submittals. These options could potentially provide states with flexibility in addressing contingencies where one or more states submit plan components that are not approvable. In such instances, these options would simplify EPA approval of remaining common or individual portions of a multi-state plan. These options might also address contingencies during plan development where a state fails to finalize its participation in a multi-state plan, with minimal disruption to the submittals of the remaining participating states.

First, the EPA is seeking comment on whether states participating in a multi-state plan should also be given the option of providing a single submittal—signed by authorized officials from each participating state — that addresses common plan elements. Individual participating states would also be required to provide individual submittals that provide state-specific elements of the multi-state plan. Both the common multi-state submittal and each individual participating state submittal would be required to address all twelve plan components described below (even if only through cross reference to either the common submittal or individual submittals, as appropriate). Under this approach, the combined common submittal and each of the individual participating state submittals would constitute the multi-state plan submitted for EPA review.

Second, the EPA is seeking comment on an approach where all states participating in a multi-state plan separately make individual submittals that address all elements of the multi-state plan. These submittals would need to be materially consistent for all common plan elements that apply to all participating states, and would also address individual state-specific aspects of the multi-state plan. Each individual state plan submittal would need to address all twelve plan components.

The EPA proposes that each plan must have the following twelve components, except as indicated otherwise for self-correcting plans:

1. Identification of Affected Entities (Affected EGUs and Other Responsible Parties)

A state plan must list the individual affected EGUs in the state that are subject to the plan and provide an inventory of CO_2 emissions from those units (for the most recent calendar year prior to plan submission for which data are available), and identify any other affected entities in a state plan with responsibilities for implementation and enforceable obligations under the plan.

2. Description of Plan Approach and Geographic Scope

The state plan must describe its approach and geographic scope, including whether the state will achieve its required level of CO_2 emission performance on an individual state basis or jointly through a multi-state demonstration.

3. Identification of State Emission Performance Level

The state plan must identify the state's proposed emission performance level, which will either be the rate-based CO_2 emission goal identified for the state in the emission guidelines or a translation of the rate-based goal to a mass-based goal.

A state plan must identify the rate-based or mass-based level of emission performance that must be met through the plan, (expressed in numeric values, including the units of measurement for the level of performance, such as pounds of CO_2 per net MWh of useful energy output or tons of CO_2). As noted, in the emission guidelines, the EPA will establish the state goal in the form of a CO_2 emission rate, and the state may, for its emission performance level, either adopt that rate or translate it into a mass-based goal. If the plan adopts a mass-based goal, the plan must include a description of the analytic process, tools, methods, and assumptions used to translate from the rate-based goal to the mass-based goal.

The EPA is proposing that multiple states could jointly demonstrate emission performance by affected EGUs. For these multi-state approaches, states would demonstrate emission performance by affected EGUs in aggregate with partner states. For states participating in a multi-state approach, the individual state performance goals in the emission guidelines would be replaced with an equivalent multi-state performance goal. For example, states taking a rate-based approach would demonstrate that all affected EGUs subject to the multi-state plan achieve a weighted average CO_2 emission rate that is consistent, in aggregate, with an aggregation of the state-specific rate-based CO_2 emission performance goals established in the emission guidelines that apply to each of the participating states. If states were taking a mass-based approach, participating states would demonstrate that all affected EGUs subject to the multi-state plan emit a total tonnage of CO_2 emissions consistent with a translated multi-state mass-based goal. This multi-state mass-based goal would be based on translation of an aggregation of the state-specific rate-based CO_2 emission performance goals established in the emission guidelines that apply to each of the participating states.

The EPA is seeking comment on two options for calculating a weighted average, rate-based CO_2 emission performance goal for multiple states. Under the first option, the weighted average emission rate goal for a group of participating states is computed using each state's emission rate goal from the emission guidelines and the quantity of electricity generation by affected EGUs in each of those states during the 2012 base year that the EPA used in calculating the state-specific goals. Different levels would be computed for the interim and final goals. This approach is consistent with the method used to calculate the state-specific, rate-based emission performance goals. However, it does not address the fact

that the weighted average emission rate performance goal for multiple states may be influenced significantly by the weighting of electricity generation from affected EGUs in different states. This mix of generation among affected EGUs in different states could differ significantly during the plan performance periods from that during the 2012 base year.

Under the second option, the weighted average emission rate goal for a group of participating states is computed using each state-specific emission rate goal and the quantity of projected electricity generation by affected EGUs in each state. The calculation would be performed for the 2020 through 2029 period to produce a multi-state interim goal, and for 2030 to produce a multi-state final goal. This projection of electricity generation by affected EGUs would be for a reference case that does not include application of either the state-specific rate-based emission performance goals for the participating states or the requirements, programs, and measures included in the multi-state plan. This approach addresses the fact that the mix of generation among affected EGUs in different states could differ significantly during the plan performance periods from that during the 2012 base year. As a result, it would base the weighted average goal in part on the anticipated business-as-usual mix of generation by affected EGUs across the multiple states during the plan performance period. However, this approach could also significantly alter the weighted average performance goal based on projected retirements of affected EGUs in one or more states.

Under both options, the rate-based multi-state goal could be translated to a mass-based goal. These options, and the procedure for translation to a mass-based goal, are discussed in more detail in the Projecting EGU CO_2 Emission Performance in State Plans TSD.

We are requesting comment on whether, to assist states that seek to translate the rate-based goal into a mass-based goal, the EPA should provide a presumptive translation of rate-based goals to mass-based goals for all states, for those who request it, and/or for multi-state regions. As another alternative, the EPA could provide guidance for states to use in translating a rate-based goal to a mass-based goal for individual states and for multi-state regions. This could include information about acceptable analytical methods and tools, as well as default input assumptions for key parameters that will likely influence projections, such as electricity load forecasts and projected fossil fuel prices. Under this approach, the EPA might also provide a coordinating function in addressing the assumptions applied by multiple states within a grid region, acknowledging that assumptions about state programs across a broader grid region that are included in an analysis scenario may influence projections of CO_2 emissions by affected EGUs in one or more particular states in the grid region. The agency is seeking comment on the process for establishing mass-based emission goals, including the options summarized above for the EPA's and states' roles in the translation process.

Technical considerations involved in translating from rate-based goals to mass-based goals are discussed in detail in the Projecting EGU CO_2 Emission Performance in State Plans TSD. The TSD includes a discussion of possible acceptable analytical methods, tools, and key assumption inputs that will influence projections. The agency invites comment on these technical considerations.

4. Demonstration That the Plan Is Projected To Achieve the State's Emission Performance Level

A state plan must demonstrate that the actions taken pursuant to the plan are, when taken together, projected to achieve emission performance by affected entities that, on average, will meet the state's required emission performance level for affected EGUs during the initial 2020–2029 plan performance period, and will meet the required final emission performance level in 2030. This demonstration will include a detailed description of the analytic process, tools, and assumptions used to project future CO_2 emission performance by affected EGUs under the plan and the results of the analysis. Considerations related to projecting the emission performance of affected EGUs under a state plan are discussed in section VIII.F.7 and in the Projecting EGU CO_2 Emission Performance in State Plans TSD.

5. Milestones

As described in greater detail in Section VIII.B.2.d., state plans must include periodic programmatic milestones to show progress in program implementation if the plan is not self-correcting (i.e., does not inherently require both interim progress and the full level of required emission performance in a manner that is federally enforceable against affected EGUs). These programmatic milestones with specific dates for achievement should be appropriate to the programs and measures included in the plan.

In addition, the state plan demonstration will indicate the plan's intended trajectory of emission performance improvement. As described in Section VIII.B.2.d., each year during the interim performance period, beginning in 2022 the state must compare the collective emission performance achieved by affected entities in the state during the previous two-year period with performance projected in the state plan. If actual emission performance is not within 10 percent of original projections, the state must submit a report by the July 1 following the end of the two-year period (submitted as part of the state's annual report on plan performance described below in section VIII.D.10) to explain reasons for the deviation and specify the corrective actions that will be taken to ensure that the required level of emission performance in the plan will be met.

6. Corrective Measures

For a plan that does not include self-correcting mechanisms, the plan must also specify corrective measures that will be implemented if the state's progress in achieving its level of performance for affected EGUs falls short of what is projected under the plan, as well as a process and schedule for implementing any such measures. The agency requests comment on the amount of emission rate improvement or emission reduction that the corrective measures included in the plan must be designed to achieve (e.g., measures sufficient to address a 10 percent performance deficiency). The agency also seeks comment on whether the emission guidelines should establish a deadline for implementation of corrective measures (e.g., two years from the July 1 deadline described above for reporting the deficiency as part of the state's annual report on plan performance). Corrective measure provisions are discussed in more detail above in section VIII.B.2.d and in section VIII.B.2.f.

7. Identification of Emission Standards and Any Other Measures

A state plan must identify the affected entities to which each emission standard applies (e.g., individual affected EGUs, groups of affected EGUs, all the state's affected EGUs in aggregate, other affected entities that are not EGUs), as well as any implementing and enforcing measures for such standards, and describe each emission standard and the process for demonstrating compliance with it pursuant to state regulations or another legal instrument, including the schedule

for compliance for each affected entity. In its proposed Carbon Pollution Standards (79 FR 1430–1519, January 8, 2014), the EPA proposed that the appropriate averaging time for an emission standard for new EGUs be no longer than 12 months. Similarly, the EPA proposes here that an appropriate averaging time for any rate-based emission standard for affected EGUs and/or other affected entities subject to a state plan is no longer than 12 months within a plan performance period and no longer than three years for a mass-based standard. We also solicit comment on longer and shorter averaging times for emission standards included in a state plan.

8. Demonstration That Each Emission Standard Is Quantifiable, Non-Duplicative, Permanent, Verifiable, and Enforceable

In developing its CAA section 111(d) plan, a state must ensure that its plan is enforceable and in conformance with the CAA. As discussed in section VIII.C.1, we are seeking comment on the appropriateness of existing EPA guidance on enforceability in the context of state plans under CAA section 111(d), considering the types of affected entities that might be included in a state plan.[286] This guidance serves as the foundation for the types of monitoring, reporting, and limits that the EPA has found can be, as a practical matter, enforced, and set forth the general principle that a requirement that is enforceable as a practical matter is one that is quantifiable, verifiable, straightforward and is calculated over as short a term as reasonable.

As discussed in section VIII.F.1, the EPA is seeking comment on whether the agency should provide guidance on enforceability considerations related to requirements in a state plan for entities other than affected EGUs (and if so, which types of entities). Also, as discussed in section VIII.F.4, the EPA intends to develop guidance for evaluation, monitoring, and verification (EM&V) of renewable energy and demand-side energy efficiency programs and measures incorporated in state plans.

For each emission standard, a plan must describe how it is quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to an affected entity. An emission standard is quantifiable if it can be reliably measured, using technically sound methods, in a manner that can be replicated. These issues are discussed further in Section VIII.F.4 and in the State Plan Considerations TSD.

An emission standard is non-duplicative with respect to an affected entity if it is not already incorporated in another state plan, except in instances where incorporated in another state as part of a multi-state plan. An example of a duplicative emission standard would occur where recognition of avoided CO_2 emissions from, for example, a wind farm, could be applied in more than one state's CAA section 111(d) plan, except in the case of a multi-state plan where recognition is assigned among states or emission performance is demonstrated jointly for all affected EGUs subject to the multi-state plan. This does not mean that measures in an emission standard cannot also be used for other purposes. For example, if a state wished to take credit for CO_2 emissions avoided due to electric generation from a new wind farm, those avoided emissions could be considered non-duplicative and included for purposes of CAA section 111(d), even if electric generation from that wind farm was also being used to generate renewable energy certificates (RECs) to comply with the state's RPS requirements. It also does not mean that a single affected entity could not be subject to similar emission standards in different state plans. For example, an affected entity might be an electric distribution utility that has a service territory that crosses state lines. This entity might be subject to a separate state demand-side EE requirement for electricity supplied in each of the states where it serves electricity customers. In this instance, the same company could be an affected entity subject to a different state demand-side EE requirement in each state plan, without these emission standards in each plan being considered duplicative. The EPA solicits comment on whether an emission reduction becomes duplicative (and therefore cannot be used for demonstrating performance in a plan) if it is used as part of another state's demonstration of emission performance under its CAA section 111(d) plan.

An emission standard is permanent if the standard must be met for each applicable compliance year or period, or replaced by another emission standard in a plan revision, or the state demonstrates in a plan revision that the emission standard is no longer necessary for the state to meet its required emission performance level for affected EGUs.

An emission standard is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with it. This is discussed further in Section VIII.F.4 and in the State Plan Considerations TSD. An emission standard is enforceable if: (1) It represents a technically accurate limitation or requirement and the time period for the limitation or requirement is specified, (2) compliance requirements are clearly defined, (3) the affected entities responsible for compliance and liable for violations can be identified, (4) each compliance activity or measure is practically enforceable in accordance with EPA guidance on practical enforceability (as discussed in Section VIII.F.1 of this preamble), and the Administrator and the state maintain the ability to enforce against violations and secure appropriate corrective actions pursuant to CAA sections 113(a)–(h).

9. Identification of Monitoring, Reporting, and Recordkeeping Requirements

The state plan must describe the CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs, including requirements for monitoring and reporting of useful energy output if a state plan is taking a rate-based approach. The EPA is proposing that each plan include monitoring, reporting, and recordkeeping requirements for CO_2 emissions and useful energy output (if applicable) that are materially consistent with the requirements specified in the emission guidelines. State plans with a rate-based form of the emission performance level must require affected EGUs to report hourly net energy output (including net MWh generation, and where applicable, useful thermal output) to the EPA on an annual basis.

Most affected EGUs already monitor CO_2 emissions under 40 CFR Part 75 and report the data using the EPA's Emission Collection and Monitoring Plan System (ECMPS), which would generally satisfy CO_2 emission reporting requirements under the proposed guidelines. However, we are seeking comment on two possible adjustments to the Part 75 Relative Accuracy Test Audit (RATA) requirements for steam EGU stack gas flow monitors that can affect reported CO_2 emissions. The first possible adjustment would be to require use of the most accurate RATA

[286] EPA guidance on enforceability includes: (1) September 23, 1987 memorandum and accompanying implementing guidance, ''Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency,'' (2) August 5, 2004 ''Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures,'' and (3) July 2012 ''Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F.''

reference method for specific stack configurations, while the second possible adjustment would be to require a computation adjustment when an EGU changes RATA reference methods. The rationale for these possible adjustments is described further in the Part 75 Monitoring and Reporting Considerations TSD available in the docket.

We are also proposing monitoring and reporting protocols for net energy output under 40 CFR Part 75 that would allow the ECMPS to be used for purposes of meeting the net energy output reporting requirement. Affected facilities with multiple generators (e.g., combined cycle facilities) would be required to report the electric output from all generators. The proposed protocols include a default apportionment procedure for multi-EGU facilities under which the net generation of each EGU at the facility would be determined as the net generation of the facility multiplied by the ratio of the EGU's gross generation to the sum of the gross generation for all EGUs at the facility. (In the case of EGUs producing both electric energy output and useful thermal output, the apportionment procedure would include a thermal-to-electric energy conversion calculation as provided in the proposed EGU GHG NSPS regulations.[287]) We solicit comment on whether EGUs producing both electric energy output and useful thermal output should be required to report both electric and useful thermal output. In addition, the proposed protocols would allow facilities to use alternative apportionment procedures with EPA approval. We invite comment on the proposal for reporting of net rather than gross energy output and on the proposed protocols. Specifically, we are seeking comment on: Any existing protocols for reporting net output (FERC, NERC, etc.); electricity meter specifications; electricity meter quality assurance testing and reporting procedures; apportionment procedures for parasitic load at multi-unit facilities; treatment of externally provided electricity; and monitoring and quality assurance testing and reporting procedures for non-electric energy output at CHP units. (Options regarding these topics are discussed in the TSD mentioned above.) Also, consistent with the requests for comment in the proposed CAA section 111(b) GHG NSPS regulations for modified and reconstructed sources, we invite comment here on a range of two-thirds to 100 percent credit for useful thermal output in the final rule, or other alternatives to better align incentives with avoided emissions.

A state plan that contains other emission standards, in addition to emission limits applicable to affected EGUs, must include additional reporting and recordkeeping requirements related to these other measures. These reporting and recordkeeping requirements will consist of the data necessary for each affected entity to demonstrate compliance with its obligations. This could include, for example, reporting of MWh electricity savings achieved by an electric distribution utility under an end-use energy efficiency resource standard and utility compliance with requirements of the standard. These requirements might also include comparable reporting by an electric distribution utility of renewable energy certificates (RECs) held, or renewable energy purchased or generated, under a renewable energy portfolio standard, and compliance with the standard. This is discussed further in Section VIII.F.5 and the State Plan Considerations TSD.

The EPA is proposing that state plans must include a record retention requirement of ten years, and we request comment on this proposed timeframe.

10. Description of State Reporting

A state plan must provide that the state will submit reports to the EPA detailing plan implementation and progress, including the actions taken by the state, affected EGUs, and any other affected entities under the plan; the status of compliance by affected EGUs and any other affected entities with their obligations under the plan; current aggregate and individual CO_2 emission performance by affected EGUs during the reporting year and prior reporting years; and any additional measures applied under the plan during the reporting period. The state plan must describe the process, timing, and content for these reports. The EPA is proposing that an annual report is due no later than the July 1 following the end of the reporting year.

While some of the proposed reporting requirements such as reporting of EGU emissions (which can be done through existing reporting mechanisms) would not place additional burdens on states, others may require assembling information that is being reported under state programs into a single report. For example, in the case of a rate-based state plan that calls for adjusting the actual emission rate of the state's affected EGUs based on emissions avoided through renewable energy or end-use energy efficiency programs, the requirement for comparing actual plan performance against projected plan performance requires the state to incorporate information on results achieved by those programs each year. This emission performance comparison serves as the basis for showing either that a state plan is on track or that corrective measures are needed. Another reporting element is a list of facilities and their compliance status. The EPA is requesting comment on the appropriate frequency of reporting of the different proposed reporting elements, considering both the goals of minimizing unnecessary burdens on states and ensuring program effectiveness. In particular, the agency requests comment on whether full reports containing all of the report elements should only be required every two years.

In addition, the EPA is soliciting comment on whether these reports should be submitted electronically, to streamline transmission.

11. Certification of State Plan Hearing

A state plan must provide certification that a hearing on the state plan was held, a list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission pursuant to the requirements of the EPA framework regulations at 40 CFR 60.23–60.29.

12. Supporting Material

The state must provide supporting material and technical documentation related to applicable components of the plan. In its plan, a state must adequately demonstrate that it has the legal authority for each implementation and enforcement component that it has included in its plan as part of a federally enforceable emission standard. A state can make such a demonstration by providing supporting material related to the state's legal authority used to implement and enforce each component of the plan, such as statutes, regulations, public utility commission orders, and any other applicable legal instruments.

A state plan must also provide analytical materials used in translating a rate-based goal to a mass-based goal (if a translation is included), analytical materials used in projecting emission performance that will be achieved through the plan, relevant implementation materials, and any additional technical requirements and guidance the state proposes to use to implement elements of the plan.

[287] 70 FR 1429–1519; January 8, 2014.

E. Process for State Plan Submittal and Review

1. Overview

Under the framework regulations, state plans would be due nine months after finalization of the emission guidelines. 40 CFR 60.23(a)(1). The President in his June 25, 2013 Memorandum specified that states should submit plans by June 30, 2016, which would provide states thirteen months. During the outreach process, many states expressed concern that this was not sufficient time to prepare and submit a state plan to the EPA. States commented that additional time was needed to accommodate, among other things, state legislative and rulemaking schedules, coordination among states involved in multi-state plans, coordination with third parties, and the complex technical work needed to develop a state plan. The EPA recognizes that state administrative procedures can be lengthy, some states may need new legislative authority, and states planning to join in a multi-state plan will likely need more than thirteen months to get necessary elements in place. Balanced against that concern, however, is the urgency of addressing carbon emissions and the fact that there are certain steps we believe states can take within thirteen months to set themselves on a clear path to adoption of a complete plan. Therefore, the EPA is proposing a plan submittal process with a submittal date of June 30, 2016 (thirteen months after the expected finalization date of the emission guidelines), which provides additional time to submit a complete plan to the EPA after June 30, 2016, when justified. Part of that justification would include the state's demonstration of having taken meaningful steps during the first thirteen months toward submitting a complete plan. This approach involves the option that we refer to as an initial submittal, followed by submittal of a complete state plan no later than either June 30, 2017 for single-state plans or June 30, 2018 for multi-state plans.

In addition, for states wishing to participate in a multi-state plan, the EPA is proposing that only one multi-state plan would be submitted on behalf of all participating states, provided it is signed by authorized officials for each of the states participating in the multi-state plan and contains the necessary regulations, laws, etc. for each state in the multi-state plan. In this instance, the joint submittal would have the same legal effect as an individual submittal for each participating state.

2. State Plan Submittal and Timing

The EPA framework regulations (40 CFR 60.23) require that state plans be submitted to the EPA within nine months of promulgation of the emission guidelines, unless the EPA specifies otherwise.[288] In view of the potential that these plans may require states to develop new regulatory or statutory authority, we are proposing that each state must submit a plan to the EPA by June 30, 2016, which is more than one year after the expected finalization date of the emission guidelines. The state may submit a complete plan, or if justified, an initial plan that documents the state's progress in preparing a complete plan. To qualify for an extension of the June 30, 2016 deadline for submitting a complete plan, the state must submit an initial plan that demonstrates the state is on track to develop a complete plan and that includes meaningful steps that clearly commit the state to complete an approvable plan.

The EPA proposes that approvable justifications for seeking an extension beyond 2016 for submitting a complete plan include: A state's required schedule for legislative approval and administrative rulemaking, the need for multi-state coordination in the development of an individual state plan, or the process and coordination necessary to develop a multi-state plan. The EPA is requesting comment on other circumstances for which an extension of time would be appropriate. We are also seeking comment on whether some justifications for extension should not be permissible.

If a state submits an initial state plan by June 30, 2016, and it meets the minimum requirements for an initial state plan, as specified in the plan guidelines, then the deadline extension for submitting a complete plan that the state requested will be deemed granted. If the EPA determines that the initial plan does not meet the guidelines, the EPA will notify the state by letter, within 60 days, that the agency cannot approve the state's initial plan as submitted. The EPA believes this approach is authorized by, and consistent with, section 60.27(a) of the implementing regulations.

If the EPA approves a two-year extension to June 30, 2018, for a state developing a multi-state plan, the state would be required to provide one update, on June 30, 2017, on its progress toward milestones and schedules in the initial plan for developing and submitting a complete plan. We are requesting comment on this approach and the timing and frequency of updates that the state must provide.

3. Components of an Initial State Plan Submittal and Approvability Criteria

As noted, if a state is unable to prepare and submit a complete plan by June 30, 2016, the state must make an initial submittal by that date. To be approved, the EPA proposes that the initial plan must address all components of a complete plan, including identifying which components are not complete. For incomplete components, an approvable initial submittal must contain a comprehensive roadmap outlining the path to completion, including milestones and dates. We recognize that certain options that states may choose involve more analytic effort to precisely demonstrate sources of emission reductions than other options.

The EPA is proposing that the state must provide an opportunity for public comment on a substantial draft of its initial submittal. The EPA proposes that this public comment opportunity will not be governed by the procedural requirements of the framework regulations that apply to the state's adoption of a complete plan, such as the requirement that the state hold a public hearing. 40 CFR 60.23(c)–(f). An initial plan might not include any legally enforceable provisions that the state would have adopted through its administrative or legislative processes, which generally provide for public input. Therefore, to ensure that the public has an opportunity to understand and inform the initial plan, the EPA is proposing that prior to submittal on June 30, 2016 the state must have provided a reasonable opportunity for public comment on a substantial draft of the initial submittal, with notice to the EPA of that comment period. The EPA can use this comment opportunity to advise the state whether it is on track to submit an approvable initial plan. When the state submits its initial plan, it must provide the EPA with a response to any significant comments it received on issues relating to the approvability of the initial plan so that the EPA can fully assess whether it is approvable.

To be approvable, the initial plan must include the following information:

- A description of the plan approach and progress to date in developing a complete plan.
- Initial quantification of the level of emission performance that will be achieved through the plan.
- A commitment to maintain existing measures that limit or avoid CO_2 emissions (e.g., renewable energy

[288] 40 CFR 60.23(a)(1).

standards, unit-specific limits on operation or fuel utilization), at least until the complete plan is approved.

- A comprehensive roadmap for completing the plan, including process, analytical methods, and schedule (with milestones) specifying when all necessary plan components will be complete (e.g., demonstration of projected plan performance; implementing legislation, regulations and agreements; any necessary approvals).
- Identification of existing programs, if any, the state intends to rely on to meet its emission performance level.
- Identification of executed agreements with other states (e.g., memorandum of understanding (MOU)), if a multi-state approach is being pursued.
- A commitment to submit a complete plan by no later than the applicable required date and explanation of actions the state will take to show progress in addressing incomplete plan components.
- A description of all steps the state has already taken in furtherance of actions needed to finalize a complete plan (e.g., copies of draft or proposed regulations, draft or introduced legislation, or draft implementation materials).
- Evidence of an opportunity for public comment and a response to any significant comments received on issues relating to the approvability of the initial plan.

The EPA is soliciting comment on whether there are other elements that a state must include in its initial submittal to qualify for a date extension. Specifically, the EPA requests comment on whether the guidelines should require a state to have taken significant, concrete steps toward adopting a complete plan for the initial plan to be approvable. For example, while it may be difficult for a state to complete its administrative or legislative process within thirteen months, it may be reasonable to require that a state must document that it has at least proposed any necessary regulations and introduced any necessary legislation within the first thirteen months to qualify for additional time to submit a complete plan.

For states participating in a multi-state program, the initial submittal should include executed agreements among the participating states and a road map for both design of the multi-state program and its implementation at the state level. The RGGI provides an example of such an approach. The RGGI participating states signed a Memorandum of Understanding (MOU) in December 20, 2005, in which the states ''express[ed] their mutual understandings and commitments''.[289] The MOU included a detailed outline of the multi-state emission budget trading program, which served as a guide for drafting a model rule. The MOU also included commitments by the participating states to draft and finalize the model rule by specified dates, and a commitment to seek to establish in statute and/or regulation a program materially consistent with the model rule in each state by a specified date.[290] The MOU also included a commitment to launch the program by January 1, 2009 in all states and specified a process for establishing a non-profit organization to assist the states in administering the regional aspects of the program. In addition, prior to execution of the MOU, the RGGI states committed, through letters from the Governors of participating states, to engage in the development of a market-based program to reduce CO_2 emissions from power plants. This was followed by publication of an action plan for tasks leading up to agreement on the basic structure of the program, which was ultimately formalized in the MOU.

4. Process for EPA Review of State Plans

Following the June 30, 2016, deadline for state plan submittals, the EPA will review plan submittals for approvability. For a state that submits an initial state plan by June 30, 2016, and requests an extension of the deadline for the submission of a complete state plan, the EPA will determine if the initial plan submittal meets the minimum requirements for an initial state plan. If it meets the minimum requirements for an initial state plan, as specified in the emission guidelines, the state's request for a deadline extension to submit a complete plan will be deemed granted, and the complete plan must be submitted to the EPA by no later than June 30, 2017 or June 30, 2018 as appropriate.

After receipt of a complete plan submittal, the EPA proposes that the agency will review the plan and, within twelve months, approve or disapprove the plan through a notice-and-comment rulemaking process, similar to that used for approving state implementation plan submittals under section 110 of the CAA. The framework regulations currently provide for the EPA to act on a complete plan within four months. 40 CFR 60.27(b). The EPA proposes that for plans under these guidelines, the agency will act on a complete plan within twelve months to provide adequate time for rulemaking procedures.

Currently, the EPA's framework regulations do not explicitly provide for the EPA to use the different forms of approval actions Congress introduced into the SIP program in the 1990 Clean Air Act Amendments. The EPA is taking comment on whether, for complete state plans under these guidelines, the agency may use two approval mechanisms provided for in CAA sections 110(k)(3) and (4), 42 U.S.C. 7410(k)(3) and (4). CAA section 111(d)(1) provides that the EPA shall establish ''a procedure similar to that provided by section 7410 of this title [section 110 of the Act].'' The EPA is considering whether to update the procedures for acting on complete state plans under the guideline to reflect the enhancements Congress included in CAA section 110 for agency actions on state implementation plans.

The first mechanism is a partial approval/partial disapproval. Where a CAA section 111(d) plan includes severable provisions, some of which are approvable and some of which are not, the EPA is taking comment on whether the agency should interpret the CAA as providing the flexibility to approve those elements that meet the requirements of this guideline, while disapproving those elements that do not. Any plan that is partially approved and partially disapproved would not fully discharge the state's obligation to submit a fully approvable plan, but the partial approval would make federally enforceable those elements of the state's plan that comply with these guidelines.

The second mechanism is a conditional approval. Where a CAA section 111(d) plan is substantially approvable and requires only minor amendments to fully meet the requirements of these guidelines, the EPA is taking comment on whether the agency should interpret the CAA as providing the flexibility to approve that plan on the condition that the state commits to curing the minor deficiencies within one year. Any such conditional approval would be treated as a disapproval if the state fails to comply with its commitment. During the year following the conditional approval while the state works to cure

[289] Regional Greenhouse Gas Initiative Memorandum of Understanding, available at *http://rggi.org/design/history/mou*. Two states subsequently signed the original MOU in early 2007 and a third joined the program later that year through an amendment of the MOU; one of the original states withdrew from the MOU in late 2011.

[290] The model rule specified elements that needed to be consistent across states for the program to function, as well as areas where state rules could differ (e.g., the method used for allocating CO_2 allowances). For more information, see Regional Greenhouse Gas Initiative Model Rule, available at *http://rggi.org/docs/ProgramReview/FinalProgramReviewMaterials/Model_Rule_FINAL.pdf*.

the deficiency identified in the condition, the state's plan would be federally enforceable.

The EPA has seen that these mechanisms have proven useful when reviewing and acting on state implementation plan submittals under CAA section 110. They allow the state, the EPA, and citizens to enforce good elements of plans or plans that are substantially complete while the state and the EPA work together to put in place a fully approvable plan. The agency notes that complete plan submittals under these guidelines, like SIPs that implement air quality standards, also may contain multiple program elements.

5. Failure To Submit a Complete Plan

If a state fails to submit a complete plan by the applicable deadline, the EPA will notify the state by letter of its failure to submit. The EPA will publish a **Federal Register** notice informing the public of any such notifications. When appropriate, the agency may batch the publication of such notices periodically to simplify publication.

6. Modification of an Approved State Plan

During the course of implementation of an approved state plan, a state may wish to update or alter one or more of the enforceable measures in the state plan, or replace certain existing measures with new measures. The EPA proposes that the state may revise its state plan provided that the revision does not result in reducing the required emission performance for affected EGUs specified in the original approved plan. In other words, no ''backsliding'' on overall plan emission performance through a plan modification would be allowed.

If the state wishes to revise enforceable measures in its approved state plan, the EPA proposes that the state must submit the revised enforceable measures to the EPA and demonstrate that the revised set of enforceable measures in the modified plan will result in emission performance at affected EGUs that is equivalent to or better than the level of emission performance required by the original state plan. In the case of minor changes to enforceable measures, this showing may be a simple explanation of why the changes will not alter the emission performance of affected EGUs under the state plan, or will clearly improve the emission performance of affected EGUs under the state plan. In the case of more substantive changes to enforceable measures, or substitution of a new measure for an old measure, new projections of emission performance under the modified plan would be needed to demonstrate that the modified plan will meet the required level of emission performance for affected EGUs specified in the original approved plan. The EPA requests comment on whether, for such new projections of emission performance, the projection methods, tools, and assumptions used should match those used for the projection in the original demonstration of plan performance, or should be updated to reflect the latest data and assumptions, such as assumptions for current and future economic conditions and technology cost and performance.

7. Plan Templates and Electronic Submittal

The EPA is seeking comment on the creation of a template for initial and complete state plan submittals. A plan template would provide a framework that includes all of the necessary components for an initial and complete submittal that could be populated by states. This could assist states in compiling their plan submittals and streamline EPA review by assuring greater consistency in the format and organization of submittals. This would provide greater certainty for states about what they need to include in a submittal and allow the EPA to provide a quicker response to states about the completeness and approvability of submittals. We are further seeking comment on whether a template may be more appropriate for initial plan submittals than complete plans. Initial plan submittals are likely to be more similar across states, compared to complete plans, which may include a diverse range of components, depending on the state plan approach.

The EPA is also seeking comment on whether it should provide for, or require, electronic submittal of initial and complete plans. It is the EPA's experience that the electronic submittal of information increases the ease and efficiency of data submittal and data accessibility. We note that a number of states have requested an electronic submittal process for state implementation plans (SIPs) under CAA section 110, and the EPA has implemented a pilot program with a number of states for electronic submittal of such plans. The Electronic State Implementation Plan Submission Pilot (eSIPS) includes an EPA-state workgroup that has developed and will evaluate an electronic submission process. This pilot will use the EPA's Central Data Exchange (CDX) electronic submission system. We are seeking comment on the suitability of such an approach for submittal of state plans under CAA section 111(d).

F. State Plan Considerations

The EPA is proposing to give states broad discretion to develop plans that best suit their circumstances and policy objectives. In developing its plan, a state will need to make a number of decisions that will require careful consideration, in order to ensure that its plan both meets the state's policy objectives and is approvable by the EPA. In this section, we identify several key decision points and factors that states should consider when developing their plans.

The EPA has also prepared a TSD, titled ''State Plan Considerations,'' that provides further information on these topics. The agency is seeking comment on the contents of this TSD and all aspects of the state plan decision points and factors below.

1. Affected Entities Other Than Affected EGUs

A state will need to identify each affected entity responsible for meeting compliance obligations under its plan and the means by which compliance with each plan requirement will be met, as well as demonstrate that it has the legal authority to subject such entities to the federally enforceable requirements specified in its state plan. We are proposing that affected entities in an approvable state plan may include: An owner or operator of an affected EGU, other affected entities with responsibilities assigned by a state (e.g., an entity that is regulated by the state, such as an electric distribution utility, or a private or public third-party entity), and a state agency, authority or entity. We are seeking comment on other appropriate examples of affected entities beyond the affected EGUs.

While the EPA seeks to provide states with broad discretion to develop plans that best suit their circumstances and policy objectives, a plan that assigns responsibility to affected entities other than affected EGUs may be more challenging to implement and enforce than a plan with requirements assigned only to affected EGUs.

Furthermore, it may be more challenging for a state to demonstrate that it has sufficient legal authority to subject such affected entities other than affected EGUs to the federally enforceable requirements specified in its state plan. We seek comment on whether the EPA should provide guidance on enforceability considerations related to requirements in a state plan for affected entities other than EGUs (and if so, which such entities). The State Plan Considerations

TSD provides illustrative examples of possible entities and legal mechanisms.

2. Treatment of Existing State Programs

a. Framing Considerations

Many state officials and stakeholders have said that the EPA should avoid structuring the CAA section 111(d) emission guidelines in a way that would disadvantage states that already have adopted programs that reduce CO_2 emissions from EGUs. The EPA agrees with that policy principle.

There is much less agreement among states and stakeholders on the specifics of how existing state programs should be treated in a demonstration that a proposed state plan will achieve the required level of emission performance.

The EPA, starting from recent historical data, has identified the affected EGU emission performance improvements and resulting average emission performance levels for affected EGUs that are achievable, considering cost, in each state over the 2020–2029 period, with achievement of the final CO_2 emission performance level by 2030.

As explained in Section VII above, the EPA's proposed state-specific goals reflect actions that many states have already taken to reduce or avoid EGU CO_2 emissions. CO_2 emission reductions due to shifts to lower CO_2-emitting power generation are also represented in the 2012 base period that was used to assess certain building blocks that are applied in calculating a state emission performance goal.[291]

The agency recognizes that states that have already shifted toward lower carbon-intensity generation or ramped up demand-side EE programs are better positioned to meet state-specific goals. For example, states where significant shifts in generation to NGCC units have already occurred would be closer to the generation mix reflected in the state goals than states where NGCC capacity is not yet being operated to the same degree. Likewise, states with relatively well-established demand-side EE programs would be able to build on those programs more quickly than states with less established programs, and would be closer to, or in some cases already achieving, the level of demand-side energy efficiency reflected in the state goals.

b. Proposed Approach for Treatment of Existing State Programs and Measures in an Approvable State Plan

The EPA is proposing that existing state programs, requirements, and measures,[292] may qualify for use in demonstrating that a state plan will achieve the required level of emission performance, provided they meet the approvability requirements in the emission guidelines (summarized above in Section VIII.C) and relevant requirements for plan components in the emission guidelines (described above in Section VIII.D). Several options for treatment of existing state programs and measures are described below.

Specifically, the EPA is proposing that, for an existing state requirement, program, or measure, a state may apply toward its required emission performance level the emission reductions that existing state programs and measures achieve during a plan performance period as a result of actions taken after the date of this proposal.[293] This proposed approach would recognize beneficial emission impacts from existing state programs and measures during a plan performance period. It would do so in a way that may be generally compatible with the forward-looking methodology that the EPA used to propose state emission performance goals based on the BSER. By making actions taken after proposal eligible to help meet a state's required emission performance level, this approach would support early beneficial emission-reducing actions. This option would ensure that actions taken after proposal of the emission guidelines and prior to 2020 as a result of requirements in a state plan, could be recognized as contributing toward meeting a state's required emission performance level for affected EGUs.

In general, the agency has identified two broad options for treatment of existing state programs and measures. As noted above, the EPA proposes that emission reductions that existing state requirements, programs and measures achieve during a plan performance period as a result of actions taken after a specified date may be recognized in determining emission performance under a state plan. While proposing that the ''specified date'' would be the date of proposal of these emission guidelines, the EPA also requests comment on the following alternatives: The start date of the initial plan performance period, the date of promulgation of the emission guidelines, the end date of the base period for the EPA's BSER-based goals analysis (e.g., the beginning of 2013 for blocks 1–3 and beginning of 2017 for block 4, end-use energy efficiency), the end of 2005, or another date.

For this option, we are seeking comment on the point in time after which such actions should be able to qualify for use during a plan performance period, considering the method used to set state goals. Whether this option is consistent in practice with the EPA's application of the BSER may depend on the date or dates that are applied for qualifying actions under existing state programs, requirements, and measures. For example, implementation of measures subsequent to the proposal or promulgation of the emission guidelines may be consistent with a forward-looking goal-setting approach, as these actions may be necessary to meet a required level of emission performance during the plan performance period or will put a state in a better position to meet the required level of performance. An example is the EPA's treatment of end-use energy efficiency potential in state goal-setting, where the energy savings achievable during the initial plan performance period are premised in part on a ramping up of end-use energy efficiency programs and cumulative energy savings prior to the beginning of the plan performance period. Earlier dates may also be consistent with a forward-looking goal-setting approach, if the goal-setting approach is premised in part on actions that could be taken prior to the initial plan performance period. However, inconsistency issues may arise if the selected date is not adequately synchronized with the goal-setting method. The EPA requests comment on whether there is a rational basis for choosing a date that predates the base period from which the EPA used historical data to derive state goals. The agency generally requests comment on the appropriate date to select under this option.

The EPA also solicits comment on a second broad option. This option would recognize emission reductions that existing state requirements, programs

[291] For example, in such instances a significant shift to NGCC generation prior to 2012 may result in a lower potential for further re-dispatch to these units, as witnessed in the 2012 base period data. This would influence the calculated rate-based emission goal for the state, reducing the percentage improvement required relative to the base period CO_2 emission rate.

[292] An ''existing measure'' refers to a state or utility requirement, program, or measure that is currently ''on the books.'' For the purposes of this discussion, this may include a legal requirement that includes current and future obligations or current programs and measures that are in place and are anticipated to be continued or expanded in the future in accordance with established plans. Existing measures may have past, current, and future impacts on EGU CO_2 emissions.

[293] We are also proposing that this proposed limitation would not apply to existing renewable energy requirements, programs and measures because existing renewable energy generation prior to the date of proposal of the emission guidelines was factored into the state-specific CO_2 goals as part of building block 3.

and measures achieved starting from a specified date prior to the initial plan performance period, as well as emission reductions achieved during a plan performance period. The specified date could be, for example: The date of promulgation of the emission guidelines; the date of proposal of the emission guidelines; the end date of the base period for the EPA's BSER-based goals analysis (e.g., the beginning of 2013 for blocks 1–3 and the beginning of 2017 for block 4, end-use energy efficiency); the end of 2005; or another date.

The EPA requests comment on this option—that emission reduction effects that occur prior to the beginning of the initial plan performance period could be applied toward meeting the required level of emission performance in a state plan. This approach would enable a state to count emission improvements achieved by state programs prior to 2020 toward its interim goal, allowing the state to begin demonstrating emission performance earlier and follow a more gradual emission improvement trajectory during the interim performance period of 2020–2029. This approach would in effect allow higher emissions during the 2020–2029 period than would occur under the proposed approach (i.e., requiring less emission performance improvement during that period). The rationale for this approach would be that higher emissions in 2020–2029 would be offset by pre-2020 emission reductions not required by the CAA section 111(d) program. However, total emissions to the atmosphere would likely be greater under this approach, unless the pre-2020 emission reductions that can be counted toward the state goal are limited to reductions that would not have occurred in the absence of the CAA section 111(d) program. To the extent that states are able to both adopt and implement new requirements earlier than 2020 (e.g., by 2018 or 2019), this approach could provide an incentive for earlier emission reductions. The agency requests comment on whether pre-2020 implementation of new requirements would be practical for states. The agency generally requests comment on this approach, including the conditions that should apply to pre-2020 emission reductions that would count toward the state goal.

The agency also requests comment on the alternative dates listed above in connection with this option. We also request comment on whether this option is inconsistent with the forward-looking method that the EPA has proposed for establishing state goals based on the application of the BSER.

The agency is seeking comment on whether some variation of this approach could be justified as consistent with the EPA's proposed goal-setting approach, as well as the general concept of the BSER and its application in establishing state goals. In particular, we are seeking comment on whether the emission effects of actions that are taken after proposal or promulgation of the emission guidelines or the approval of a state plan, but which occur prior to the beginning of the initial state plan performance period, could be applied toward meeting the required level of emission performance in a state plan.

c. Application of Options Under Rate-Based and Mass-Based Plan Approaches

Under a rate-based approach, the options described above would address the eligibility date for qualifying demand-side EE measures that, through MWh savings, avoid CO_2 emissions from affected EGUs. Measures installed after the eligibility date could generate MWh savings during a plan performance period, and related avoided CO_2 emissions, that could be applied toward meeting a required rate-based emission performance level. Under the proposed option, the eligibility date would be the date of these proposed emission guidelines. For example, under this approach, new demand-side EE measures installed in 2015 or later to meet an existing, on-the-books energy efficiency resource standard (EERS) would be a qualifying measure. However, only MWh savings beginning in 2020 and related avoided CO_2 emissions could be applied toward meeting a required rate-based emission performance level.

Under a mass-based approach, the options described above would be applied when establishing a reference case scenario projection that is used to translate a rate-based goal to a mass-based goal. For example, demand-side EE measures after a respective eligibility date would not be included in the scenario that is used to project CO_2 emissions from affected EGUs when establishing a translated mass-based emission goal. This could be achieved by not including the incremental requirements of an end-use EERS requirement in a reference case projection, beginning at a specified date. These considerations are addressed in more detail in Section VIII.F.7. below and in the Projecting CO_2 Emission Performance in State Plans TSD.

3. Incorporating RE and Demand-Side EE Measures Under a Rate-Based Approach

We are proposing that RE and demand-side EE measures may be incorporated into a rate-based approach through an adjustment or tradable credit system applied to an EGU's reported CO_2 emission rate.[294] Under such a process, measures that avoid EGU CO_2 emissions from affected EGUs, such as quantified and verified end-use energy savings and renewable energy generation, could be credited toward a demonstrated CO_2 emission rate for EGU compliance purposes or used by the state to administratively adjust the average CO_2 emission rate of affected EGUs when demonstrating achievement of the required rate-based emission performance level in a state plan.

Under this approach, affected EGUs[295] could comply with a CO_2 emission rate limit in part through the use of credits for actions that avoid CO_2 emissions from affected EGUs. If a state is implementing a portfolio approach, then the state could administratively adjust the average CO_2 emission rate of affected EGUs through a similar process, provided that the CO_2-avoiding measures are enforceable elements of the state plan.

We are seeking comment on different approaches for providing such crediting or administrative adjustment of EGU CO_2 emission rates, which are elaborated further in the State Plan Considerations TSD.

Credits or adjustment might represent avoided MWh of electric generation or avoided tons of CO_2 emissions. The approach chosen could have significant implications for the amount of adjustment or credit provided for RE and demand-side EE measures. If adjustment or credits represent avoided MWh, they would be added to the denominator when determining an adjusted lb CO_2/MWh emission rate. If adjustment or credits represent avoided CO_2 emissions, they would be subtracted from the numerator when determining an adjusted lb CO_2/MWh emission rate.

A MWh crediting or adjustment approach implicitly assumes that the avoided CO_2 emissions come directly from the particular affected EGU (or group of EGUs) to which the credits are

[294] We are also proposing that RE and demand-side EE measures could be used under a mass-based portfolio approach in an approvable state plan. However, the focus of this section is limited to application of such measures under a rate-based approach.

[295] This could include an individual affected EGU or group of affected EGUs if a rate-based averaging or trading approach is used.

applied. It assumes, in effect, that an additional emission-free MWh is being generated by that respective EGU, and that the RE or demand-side EE measure reduces CO_2 emissions from that individual EGU or group of EGUs.[296] In practice, the average or marginal CO_2 emission rate in the power pool or identified region—representing the avoided CO_2 emissions from the generating sources being displaced by a MWh of energy savings or a MWh of renewable energy generation—could differ significantly from the calculated avoided CO_2 emissions derived by adjusting the MWh output of an affected EGU.

An alternative approach is to provide an adjustment based on the estimated CO_2 emissions that are avoided from the power pool or identified region as a result of RE and demand-side EE measures. This approach implicitly assumes that the avoided CO_2 emissions come from the electric power pool or other identified region as a whole, rather than an individual EGU. The avoided CO_2 emissions are determined based on the MWh saved or generated, multiplied by a CO_2 emission rate for the power pool or region. This CO_2 emission rate could be based on the average or marginal emission rate in the power pool or region, or could be based on the emission rate that represents the required rate-based emission performance level in the plan. We invite comment on each of these possible approaches.

In addition, because some of the CO_2 emissions avoided through RE and demand-side EE measures may be from non-affected EGUs, we are seeking comment on how this might be addressed in a state plan, whether when adjusting or crediting CO_2 emission rates of affected EGUs based on the effects of RE and demand-side EE measures or otherwise. How these dynamics might be addressed, both in projections of plan performance and in actual demonstration of performance achieved under a plan, is further discussed in the State Plan Considerations TSD.

4. Quantification, Monitoring, and Verification of RE and Demand-Side EE Measures

A key consideration for state plans is the process and requirements under a state plan for quantifying, monitoring, and verifying the effect of RE and demand-side EE measures that result in electricity generation or electricity savings.

The EPA is proposing that a state plan that includes enforceable RE and demand-side EE measures must include an evaluation, measurement, and verification (EM&V) plan that explains how the effect of these measures will be determined in the course of plan implementation. An EM&V plan will specify the analytic methods, assumptions, and data sources that the state will employ during the state plan performance periods to determine the energy savings and energy generation related to RE and demand-side EE measures. An EM&V plan would be subject to EPA approval as part of a state plan. As discussed below, the EPA intends to develop guidance on acceptable EM&V methods that could be incorporated in an approvable EM&V plan that is included as part of an approvable state plan.

Utilities and states have conducted ongoing EM&V of demand-side EE and RE measures and programs for several decades. Current practice with EM&V for RE and demand-side EE programs in the U.S. is primarily defined by state public utility commission (PUC) requirements for customer-funded energy efficiency and renewable energy programs, as well as related compliance and reporting requirements for EERS and renewable portfolio standards (RPS).

The level of PUC oversight of demand-side EE programs varies from state to state, but this oversight process has generated the majority of the industry guidance and protocols for documenting energy savings from EE programs. Typically, impact evaluation reports are responsive to requirements established by PUCs and submitted (usually annually) for PUC review, approval, and use in resource planning and performance assessment. These PUC requirements generally rely upon a well-defined set of industry-standard practices and procedures. In states with the most experience implementing and overseeing demand-side EE programs, this typically includes: Use of one or more industry-standard EM&V protocols or guidelines; use of ''deemed savings values,'' [297] where appropriate, for well-understood demand-side EE measures; consideration of local factors, such as climate, building type, and occupancy; involvement of stakeholders and solicitation of expert advice regarding EM&V processes and resulting energy savings impacts; conduct of EM&V activities (e.g., direct equipment measurements, application of deemed savings, and reporting of impacts) on a regular basis; and provision of interim and annual reporting of achieved energy savings.

Despite this well-defined and generally accepted set of industry practices, many states with energy efficiency programs use different input values and assumptions in applying these practices (e.g., net versus gross savings,[298] run-time of equipment, measure lifetime). This can result in significant differences in claimed energy savings values for similar energy efficiency measures between states and utilities, even when the same measure type is installed under otherwise identical circumstances. In response to a growing awareness of this lack of cross-state comparability, policy makers, regulatory agencies, and other stakeholders are increasingly advocating for the use of common evaluation approaches across jurisdictions. A number of states and utilities in different regions of the country are already working to develop such common approaches.

For RE measures and programs, EM&V employed by states and utilities commonly relies upon a set of standard practices and procedures, such as the use of revenue-quality meters for quantifying RE generation. As a result, existing state and utility requirements and processes for quantification, monitoring, and verification of RE programs and measures generally provide a solid foundation for minimum requirements or guidance established by the EPA for state plans.

For both RE and demand-side EE measures included in state plans, additional information and reporting may be necessary to accurately quantify the avoided CO_2 emissions associated with these measures, such as information on the location and the hourly, daily, or seasonal basis of renewable energy generation or energy savings.

Current state and utility EM&V approaches for RE and demand-side EE programs and mandates are discussed in more detail in the State Plan

[296] As a result, the assumed avoided CO_2 emissions from an individual MWh of energy savings or MWh of generation from renewable energy will differ based on the reported CO_2 emission rate of the individual EGU to which the MWh is applied as an adjustment to its MWh output.

[297] Deemed savings are measure-specific stipulated values based on historical and verified data. Unlike other EM&V approaches, deemed savings approaches involve limited or no measurement activities, and are therefore a common and relatively low-cost strategy for documenting energy savings.

[298] Gross savings are the change in energy use (MWh) and demand (MW) that results directly from program-related actions taken by program participants, regardless of why they participated in a program. Net savings refer to the change in energy use and demand that is directly attributable to a particular energy efficiency program.

Considerations TSD. We are seeking comment on the suitability of these approaches in the context of an approvable state plan, and on whether harmonization of state approaches, or supplemental actions and procedures, should be required in an approvable state plan. In particular, we intend to establish guidance for acceptable quantification, monitoring, and verification of RE and demand-side EE measures for an approvable EM&V plan, and are seeking comment on critical features of such guidance, including scope, applicability, and minimum criteria.[299] We are also seeking comment on the appropriate basis for and technical resources used to establish such guidance, including consideration of existing state and utility protocols, as well as existing international, national, and regional consensus standards or protocols.[300] The EPA's goal in developing such guidance is to assure that it is consistent with industry-standard EM&V approaches for both RE and demand-side EE measures and programs, leverages the EM&V resources and infrastructure already in place in many states, and strikes a reasonable balance between EM&V costs, rigor, and the value of resulting information, while considering the specific use of such information in assessing avoided CO_2 emissions from affected EGUs.

In developing guidance, the agency does not intend to limit the types of RE and demand-side EE measures and programs that can be included in a state plan, provided that supporting EM&V is rigorous, complete, and consistent with the EPA's guidance. This approach recognizes differences among RE and demand-side EE programs and measures with respect to implementation history and experience, existence of applicable EM&V protocols and methods, and the nature and type of program oversight (e.g., whether or not a program is subject to PUC oversight). The EPA is requesting comment on the merits of this approach, including whether such guidance should identify types of RE and demand-side EE measures and programs for which evaluation of results is relatively straightforward and which are appropriate for inclusion in a state plan. Such approaches might be subject to streamlined review of EM&V protocols included in an approvable state plan, provided that such protocols are applied in accordance with industry best practices. For example, many utilities have implemented a similar core set of RE and demand-side EE measures and programs for utility customers. For these types of measures and programs, a substantial base of experience has been established nationally for the evaluation of measure and program outcomes. Other types of measures and programs, such as those that seek to alter consumer and building occupant behavior might pose quantification and verification challenges. Still other types of measures, such as state energy-efficient appliance standards and building codes, have not typically been subject to similar evaluation of energy savings results. These types of approaches might have substantial impacts, and the EPA does not want to discourage their implementation in state plans, but they might require development of appropriate quantification, monitoring, and verification protocols. The EPA and its federal partners intend to discuss the development of appropriate EM&V protocols for such measures with states in the coming years.

As an alternative to the EPA's proposed approach of allowing a broad range of RE and demand-side EE measures and programs to be included in state plans, provided that supporting EM&V documentation meets applicable minimum requirements, the EPA is requesting comment on whether guidance should limit consideration to certain well-established programs, such as those characterized in Section V.A.4.2.1 of the State Plan Considerations TSD.

5. Reporting and Recordkeeping for Affected Entities Implementing RE and Demand-Side EE Measures

If a state plan incorporates RE and demand-side EE measures under a rate-based approach or implements a mass-based portfolio approach with such measures, reporting and recordkeeping requirements for an approvable plan would differ from those applicable to an affected EGU. For example, these requirements may include compliance reporting by an electric distribution utility subject to an EERS or RPS. They may also include reporting by a vertically integrated utility implementing an approved integrated resource plan. In the latter instance, the utility might also be the owner and operator of affected EGUs, but additional reporting of quantified effects of RE and demand-side EE measures under the utility plan would be necessary to demonstrate emission performance under the state plan. In other instances, a state agency or entity or a private or public third-party entity might be implementing programs and measures that support the deployment of end-use energy efficiency and clean energy technologies that are incorporated into a state plan. In each of these instances, reporting of program compliance or program outcomes is a necessary part of an approvable plan to demonstrate emission performance under the plan.

Examples of potential reporting obligations for affected entities implementing RE and demand-side EE measures in an approvable state plan are provided in the State Plan Considerations TSD. We are seeking comment on the examples and suitability of potential approaches described in the TSD and any other appropriate reporting and recordkeeping requirements for affected entities beyond affected EGUs.

6. Treatment of Interstate Effects

The electricity system and wholesale electricity markets are interstate in nature. EGUs in one state provide electricity to customers in neighboring states. Power companies often own EGUs in more than one state and manage them as a system. EGUs are dispatched both within and across state borders.

Similarly, programs and measures in a state plan, such as RE and demand-side EE measures, may affect the performance of the interconnected electricity system beyond a state border. In addition, many state programs allow for actions in neighboring states to meet the in-state requirement or explicitly address CO_2 emissions in neighboring states. For example, many state renewable portfolio standards allow for generation by qualifying renewable energy sources in other states to count toward meeting the state portfolio requirement. Some states also apply CO_2 emission requirements related to the generation of power purchased by regulated utilities, including power imported from out of state.

The EPA recognizes the complexity of accounting for interstate effects associated with measures in a state plan in a consistent manner, to allow states to take into account the CO_2 emission reductions resulting from these programs while minimizing the likelihood of double counting. We also realize that interstate effects on CO_2 emissions from affected EGUs could be attributed in different manners in the context of an approvable state plan. The EPA is seeking comment on the options summarized below, as well as alternatives. These options and alternatives, and how they might apply to both projections of plan performance

[299] Section V.A.4 of the State Plan Considerations TSD includes a detailed description of these EM&V parameters.

[300] A list of these protocols is provided in Section V.A.3.1 of the State Plan Considerations TSD.

and reporting of achieved plan performance, are addressed in the State Plan Considerations TSD.

The EPA is proposing that, for demand-side EE measures, consistent with the approach that the EPA used in determining the BSER, a state could take into account in its plan only those CO_2 emission reductions occurring (or projected to occur) in the state that result from demand-side EE measures implemented in the state. The agency is also proposing that, for states that participate in multi-state plans, the participating states would have the flexibility to distribute the CO_2 emission reductions among states in the multi-state area, as long as the total CO_2 emission reductions claimed are equal to the total of each state's in-state emissions reductions that result from demand-side EE measures implemented in those states. We are also proposing that states could jointly demonstrate CO_2 emission performance by affected EGUs through a multi-state plan in a contiguous electric grid region, in which case attribution of emission reductions from demand-side EE measures would not be necessary. We also request comment on whether a state should be able to take credit for emission reductions out of state due to in-state EE measures if the state can demonstrate that the reductions will not be double-counted when the relevant states report on their achieved plan performance, and what such a demonstration should entail. We request comment on these and other approaches for taking into account CO_2 emission reductions from demand-side EE measures in state plans.

The EPA is proposing that, for renewable energy measures, consistent with existing state RPS policies, a state could take into account all of the CO_2 emission reductions from renewable energy measures implemented by the state, whether they occur in the state or in other states. This proposed approach for RE acknowledges the existence of renewable energy certificates (REC) that allow for interstate trading of RE attributes and the fact that a given state's RPS requirements often allow for the use of qualifying RE located in another state to be used to comply with that state's RPS.

The EPA is also seeking comment on how to avoid double counting emission reductions using this proposed approach. The agency is also proposing that states participating in multi-state plans could distribute the CO_2 emission reductions among states in the multi-state area, as long as the total CO_2 emission reductions claimed are equal to the total of each state's in-state emission reductions from RE measures. We also request comment on the option of allowing a state to take into account only those CO_2 emission reductions occurring in its state. We are also proposing that states could jointly demonstrate CO_2 emission performance by affected EGUs through a multi-state plan in a contiguous electric grid region, in which case attribution among states of emission reductions from renewable energy measures would not be necessary. We also request comment on whether a state should be able to take credit for emission reductions out of state due to renewable energy measures if the state can demonstrate that the reductions will not be double-counted when the relevant states report on their achieved plan performance, and on what such a demonstration should entail. We request comment on these and other approaches for taking into account CO_2 emission reductions from renewable energy measures.

7. Projecting Emission Performance

As proposed, an approvable state plan will include a projection of CO_2 emission performance by affected EGUs under the plan. In addition, a state plan that is using a mass-based goal in determining the required level of emission performance under the plan will include a translation of the rate-based emission goal in the emission guidelines to a mass-based goal. This translation will involve a projection of CO_2 emissions from affected EGUs during the initial 2020–2029 plan performance period and in 2030, under a scenario that assumes the rate-based goal in the emission guidelines is met.

The EPA is striving to find a balance between providing state implementation flexibility and ensuring that the emission performance required by CAA section 111(d) is properly defined in state plans and that plan performance projections have technical integrity. Each state plan must include a projection of CO_2 emission performance from affected EGUs during the multi-year plan period that will result from implementation of the plan. Depending on the type of plan approach, this will include either a projection of the average CO_2 emission rate achieved by affected EGUs or total CO_2 emissions from affected EGUs.

The credibility of state plans under CAA section 111(d) will depend in large part on ensuring credible and consistent emission performance projections in state plans. Therefore, the use of appropriate methods, tools and assumptions for such projections is critical.

Considerations for projecting emission performance under a state plan will differ depending on the type of plan. This includes differences in how inputs to projections are derived; how projections are conducted, including tools, methods and assumptions; and how aspects of a plan are represented in these projections.

In general, any material component of a state requirement or program included in a state plan that could affect emission performance by affected EGUs should be accurately represented in emission projections included in the state plan.

For example, mass-based emission budget trading programs include a number of compliance flexibility mechanisms that might impact emission performance achieved by affected EGUs subject to these programs. These include multi-year compliance periods; the ability to bank allowances issued in a previous compliance period for use in a subsequent compliance period; the use of out-of-sector project-based emission offsets; and cost-containment allowance reserves that make additional allowances available to the market if pre-established allowance price thresholds are achieved. As a result, annual emissions from affected sources subject to an emission budget trading program often differ from the established annual emission budget for affected sources. In addition, these programs may be multi-sector in nature, regulating emissions for source categories in addition to EGUs. As a result, emission projections in state plans will need to accurately account for and represent these compliance flexibilities, as well as the scope of affected sources if they are broader than EGUs affected under CAA section 111(d). Similarly, other types of state programs, such as RPS, may include flexibility mechanisms or other provisions, such as alternative compliance payment mechanisms, banking, and limits on total ratepayer impact, that affect the ultimate amount of electricity generation required under the portfolio standard. These considerations for different types of state programs are discussed in more detail in the Projecting EGU CO_2 Emission Performance in State Plans TSD.

In general, as with projections used to determine a mass-based goal, projections of emission performance under a state plan could be conducted using historical data and parameters for estimating the future impact of individual state programs and measures. Alternatively, a projection could include modeling, such as use of a capacity planning and dispatch

model.[301] This latter approach would be able to capture dynamic interactions within the electricity sector, based on system operation and market forces, including interactions among state programs and measures and the dynamics of market-based measures.

These considerations, and considerations for projecting emission performance under different types of state plan approaches, are discussed in detail in the Projecting EGU CO_2 Emission Performance in State Plans TSD.

We are seeking comment on the considerations discussed in this TSD, including options presented for how projections might be conducted in an approvable state plan, and how different types of state plan approaches are represented in these projections. We are seeking further comment on whether the EPA should develop guidance that describes acceptable projection approaches, tools, and methods for use in an approvable plan, as well as providing technical resources for conducting projections.

The ISO/RTO Council, an organization of electric grid operators, has suggested that ISOs and RTOs could provide analytic support to help states develop and implement their plans. The ISOs and RTOs have the capability to model the system-wide effects of individual state plans. Providing assistance in this way, they felt, would allow states with borders that fall within an ISO or RTO footprint to assess the system-wide impacts of potential state plan approaches. In addition, as the state implements its plan, ISO/RTO analytic support would allow the state to monitor the effects of its plan on the regional electricity system. ISO/RTO analytic capability could help states assure that their plans are consistent with region-wide system reliability. The ISO/RTO Council suggested that the EPA ask states to consult with the applicable ISO/RTO in developing their state plans. The EPA agrees with this suggestion and encourages states with borders that fall within one or more ISO or RTO footprints to consult with the relevant ISOs/RTOs.

8. Potential Emission Reduction Measures Not Used To Set Proposed Goals

States may include measures in their plans beyond those that the EPA included in its determination of the BSER. In general, any measures that meet the proposed criteria for approvable state plans could be employed in a state plan. Beyond that, under a mass-based approach, any measure that reduces affected EGU emissions—even if not included in the state plan—will, if implemented during a plan performance period, help to achieve actual emissions performance that meets the required level.

Beyond the types of state plan measures already discussed in this section of the preamble, the agency has identified a number of other measures that could also lead to CO_2 emission reductions from EGUs. These include, for example, electricity transmission and distribution efficiency improvements, retrofitting affected EGUs with partial CCS, the use of biomass-derived fuels at affected EGUs, and use of new NGCC units. Although the emission reduction methods discussed in this section are not proposed to be part of the BSER, the agency anticipates that some states may be interested in using these approaches in their state plans. The agency solicits comment on whether these measures are appropriate to include in a state plan to achieve CO_2 emission reductions from affected EGUs. In addition to the specific requests for comment related to specific technologies below, we also request comment on other measures that would be appropriate. In addition, we request comment on whether the EPA should provide specific guidance on inclusion of these measures in a state plan.

In addition, technological advances and innovations in energy and pollution control technologies will continue over time. The agency is aware that as new technologies become available or as costs of a technology drop because of technical advances, states may wish to include measures in their state plans that make use of those technologies.

To be more specific, there are multiple potential measures that can be taken at an EGU beyond heat rate improvements that will reduce CO_2 emissions. Some examples are: Including co-firing of less CO_2 intensive fuels such as natural gas, retrofit of partial CCS and use of integrated renewable technology (i.e. meeting some of the steam load in a steam turbine from a fossil unit and part of the steam load from a concentrating solar installation), and improving heat rates of oil- and gas-fired generating units. Co-firing of natural gas and the use of CCS could be incorporated into a state plan demonstration of emission performance as a reduction in the emission rate at an affected EGU in exactly the same way that heat rate reductions could be quantified. In the case of an integrated renewable and fossil unit, reductions could either be quantified as a reduction in rate, or the renewable component could be quantified in the same way other renewable reductions are quantified in the state plan.

In addition to the nuclear generation taken into account in the state goals analysis, any additional new nuclear generating units or uprating of existing nuclear units, relative to a baseline of capacity as of the date of proposal of the emission guidelines, could be a component of state plans. This baseline would be consistent with the proposed approach for treatment of existing state programs. The agency requests comment on alternative nuclear capacity baselines, including whether the date for recognizing additional non-BSER nuclear capacity should be the end of the base year used in the BSER analysis of potential nuclear capacity (i.e., 2012). In general, when considering nuclear generation in a state plan, states may wish to consider the impacts that different types of policies may have on different types of zero-emitting generation. Under a capped approach which does not provide any ''crediting'' for zero-emitting generation, the impact on all zero-emitting units should be the same. In a rate based approach that credited zero or low-emitting generation, the crediting mechanism used could result in different economic impacts on different types of zero- or low-emitting generation.

Another way that a state plan could reduce utilization and emissions from affected existing EGUs would be through construction of new NGCC—that is, NGCC on which construction commences after the date of proposal or finalization of CAA section 111(b) standards applicable to that source. (The agency's CAA section 111(d) proposal does not include new NGCC as a component of the BSER, but requests comment on that question in Section VI of this preamble.) Under a mass-based plan where an emission limit on affected EGUs would assure achievement of the required level of emission performance in the state plan, any emission reductions at affected EGUs resulting from substitution of new NGCC generation for higher-emitting generation by existing affected EGUs would automatically be reflected in mass emission reductions from affected EGUs. A state would not need to include enforceable provisions for new NGCC in its plan, under such an approach. However, under a mass-based portfolio approach, enforceable measures in a state plan might include

[301] In many cases, this approach will also require the development of parameters for estimating the future effect of individual state programs and measures, for use as input assumptions for modeling.

construction of new NGCC to replace one or more affected EGUs, perhaps as part of a utility IRP and related PUC orders. Again, the effects of new NGCC generation would be realized in reduced mass emissions from affected EGUs.

The agency requests comment on how emissions changes under a rate-based plan resulting from substitution of generation by new NGCC for generation by affected EGUs should be calculated toward a required emission performance level for affected EGUs. Specifically, considering the legal structure of CAA section 111(d), should the calculation consider only the emission reductions at affected EGUs, or should the calculation also consider the new emissions added by the new NGCC unit, which is not an affected unit under section 111(d)? Should the emissions from a new NGCC included as an enforceable measure in a mass-based state plan (e.g., in a plan using a portfolio approach) also be considered?

Similar to zero-emitting generation, states may also want to consider whether the policy design they choose sends similar or different price signals to new and existing NGCC. For instance, under a mass based program, if new NGCCs were not included, their costs would be less than the cost of an existing NGCC unit.

In respect to new fossil fuel-fired EGUs, the agency also requests comment on the concept of providing credit toward a state's required CAA section 111(d) performance level for emission performance at new CAA section 111(b) affected units that, through application of CCS, is superior to the proposed standards of performance for new EGUs. Because the EPA proposed to find that the BSER for new fossil fuel-fired boilers and IGCC units is only a partial application of CCS, we recognize that there is the potential for such units, if constructed, to obtain additional emission reductions by increasing the level of CCS and outperforming the proposed performance standards. In some cases these incremental emission reductions may represent a cost effective abatement option for states and would provide an incentive for the deployment and advancement of CCS. We invite comment on whether incremental emission reductions from new fossil fuel-fired boilers and IGCC units with CCS, based on exceeding the CAA section 111(b) performance standards for such units, should be allowed as a compliance option to help meet the emission performance level required under a CAA section 111(d) state plan.

Similarly, while the EPA did not propose to establish standards of performance for new NGCC units based on CCS under CAA section 111(b), we recognize that if a new NGCC unit were to be constructed with a CCS system, it could achieve a lower CO_2 emission rate than required by the proposed standards of performance for new NGCC units. We invite comment on whether incremental emission reductions from new NGCC units that outperform the performance standards for such units under CAA section 111(b) based on the use of CCS should be allowed as a compliance option to help meet the emission performance level required under a CAA section 111(d) state plan.

Building block 4 focuses on improving end-use energy efficiency. Another way to reduce the utilization of, and CO_2 emissions from, affected EGUs is through electricity transmission and distribution upgrades that reduce electricity losses during the delivery of electricity to end users. Just as end-use energy efficiency can reduce mass emissions from affected EGUs, so can transmission upgrades.

In addition, electricity storage technologies have the potential to enhance emission performance by reducing the need for fossil fuel-fired EGUs to provide generation during periods when intermittent wind and solar generation are unavailable due to natural conditions. States may wish to consider this possibility as they consider options for design of their plans.

The agency requests comment on whether industrial combined heat and power approaches warrant consideration as a potential way to avoid affected EGU emissions, and whether the answer depends on circumstances that depend on the type of CHP in question.

Many of the decisions that states will make while developing compliance approaches are fundamentally state decisions that will have impacts on issues important to the state, including cost to consumers and broader energy policy goals, but will not impact overall emission performance. Some decisions, however, may impact emission performance and exemplify the kinds of decisions and approaches states may be interested in pursuing. In light of the broad latitude that the EPA is seeking to afford the states, including latitude to adopt measures such as those discussed in this subsection, the EPA intends to make additional technical resources available and consider developing guidance for states, should they need such support in exploring and adopting these options. The EPA, in addition, requests comment on whether there are still other areas beyond those discussed above for which it would be useful for the EPA to provide guidance.

Through President Obama's Climate Action Plan, the Administration is working to identify new approaches to protect and restore our forests, as well as other critical landscapes including grasslands and wetlands, in the face of a changing climate. Sustainable forestry and agriculture can improve resiliency to climate change, be part of a national strategy to reduce dependence on fossil fuels, and contribute to climate change mitigation by acting as a ''sink'' for carbon. The plant growth associated with producing many of the biomass-derived fuels can, to varying degrees for different biomass feedstocks, sequester carbon from the atmosphere. For example, America's forests currently play a critical role in addressing carbon pollution, removing nearly 12 percent of total U.S. greenhouse gas emissions each year. As a result, broadly speaking, burning biomass-derived fuels for energy recovery can yield climate benefits as compared to burning conventional fossil fuels.

Many states have recognized the importance of forests and other lands for climate resilience and mitigation and have developed a variety of different sustainable forestry policies, renewable energy incentives and standards and greenhouse gas accounting procedures. Because of the positive attributes of certain biomass-derived fuels, the EPA also recognizes that biomass-derived fuels can play an important role in CO_2 emission reduction strategies. We anticipate that states likely will consider biomass-derived fuels in energy production as a way to mitigate the CO_2 emissions attributed to the energy sector and include them as part of their plans to meet the emission reduction requirements of this rule, and we think it is important to define a clear path for states to do so.

To better understand the impacts of using different types of biomass-derived fuels, the EPA is assessing the use of biomass feedstocks for energy recovery by stationary sources and has developed a draft accounting framework that the EPA's Science Advisory Board (SAB) has reviewed. The draft framework concluded that while biomass and other biogenic feedstocks have the potential to reduce the overall level of CO_2 emissions resulting from electricity generation, the contribution of biomass-derived fuels to atmospheric CO_2 is sensitive to the type of biomass feedstock used, and the way in which the feedstock is grown, processed, and ultimately combusted as a fuel for energy production. The SAB in its review similarly found that there are

circumstances in which biomass is grown, harvested and combusted in a carbon neutral fashion but commented that additional considerations are warranted.

The EPA is in the process of revising the draft framework and considering next steps, taking into account both the comments provided by the SAB and feedback from stakeholders. The EPA's biogenic CO_2 accounting framework is expected to provide important information regarding the scientific basis for assessing these biomass-derived fuels and their net atmospheric contribution of CO_2 related to the growth, harvest and use of these fuels. This information should assist both states and the EPA in assessing the impact of the use of biomass fuels in reaching emission reduction goals in the energy sector under state plans to comply with the requirements in the emission guidelines.

9. Consideration of a Facility's ''Remaining Useful Life'' in Applying Standards of Performance

In this section, the EPA discusses the relevance to this rule of the EPA regulations implementing the CAA section 111(d)(1) provision ''permit[ing] the State in applying a standard of performance to any particular source under a [111(d)] plan . . . to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.''

For the reasons discussed below, the EPA is proposing that, in this case, the flexibility provided in the state plan development process adequately allows for consideration of the remaining useful life of the affected facilities and other source-specific factors and, therefore, that separate application of the remaining useful life provision by states in the course of developing and implementing their CAA section 111(d) plans is unnecessary. The agency is requesting comment on its analysis below of the implications of the EPA's existing regulations interpreting ''useful life'' and ''other factors'' for purposes of this rulemaking.[302] The agency also requests comment on whether it would be desirable to include in regulatory text any aspects of this preamble discussion about how the provisions in the existing implementing regulations concerning source-specific factors relate to this emission guideline.

This section addresses the legal background concerning facility-specific considerations and the implications for implementation of these emission guidelines, including state emissions performance goals.

a. Legal Background

The EPA's 1975 implementing regulations [303] address remaining useful life and other facility-specific factors that might affect requirements for an existing source under section 111(d). Those regulations provide that for a pollutant such as GHGs, which have been found to endanger public health, standards of performance in state plans must be as stringent as the EPA's emission guidelines. Deviation from the standard might be appropriate where the state demonstrates with respect to a specific facility (or class of facilities):

(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.

The reference to ''[u]nreasonable cost of control resulting from plant age'' implements the statutory provision on remaining useful life. The language concerning plant location, basic process design, physical impossibility of installing controls, and ''other factors'' addresses facility-specific issues other than remaining useful life that the EPA determined that in some circumstances can affect the reasonableness of a control measure for a particular existing source.

This regulatory provision provides the EPA's default structure for implementing the remaining useful life provision of CAA section 111(d). The opening clause, however, which provides that this provision is applicable ''unless otherwise specified in the applicable subpart'' makes clear that this structure may not be appropriate in each case and that the EPA has discretion to alter the extent to which states may authorize relaxations to standards of performance that would otherwise apply to a particular source or source category, if appropriate under the circumstances of the specific source category and proposed guidelines.

b. Implications for Implementation of These Emission Guidelines

In general, the EPA notes that the implementing regulation provisions for remaining useful life and other facility-specific factors are relevant for emission guidelines in which the EPA specifies a presumptive standard of performance that must be fully and directly implemented by each individual existing source within a specified source category. Such guidelines are much more like a CAA section 111(b) standard in their form. For example, the EPA emission guidelines for sulfuric acid plants, phosphate fertilizer plants, primary aluminum plants, and Kraft pulp plants specify emission limits for sources.[304] In the case of such emission guidelines, some individual sources, by virtue of their age or other unique circumstances, may warrant special accommodation.

In these proposed guidelines for state plans to limit CO_2 from affected EGUs, the agency does not take that approach. Instead, the EPA is proposing to establish state emission performance goals for the collective group of affected EGUs in a state, leaving to each state the design of the specific requirements that fall on each affected EGU. Due to the inherent flexibility in the EPA's approach to establishing the state-specific goals, and the flexibility provided to states in developing approvable CAA section 111(d) plans to achieve those goals, the EPA's guidelines contain no emission standards that the state must apply directly to a specific EGU; therefore, no relief for individual facilities would be needed.

Rather, because of the flexibility for states to design their own standards, the states have the ability to address the issues involved with ''remaining useful life'' and ''other factors'' in the initial design of those standards, which would occur within the framework of the CAA section 111(d) plan development process. States are free to specify requirements for individual EGUs that are appropriate considering remaining useful life and other facility-specific factors.

Therefore, to the extent that a performance standard that a state may wish to adopt for affected EGUs raises facility-specific issues, the state is free to make adjustments to a particular facility's requirements on facility-specific grounds, so long as any such adjustments are reflected (along with

[302] The agency is not reopening or considering changes to this provision of the implementing regulations.

[303] 40 CFR 60.24(f).

[304] *See* ''Phosphate Fertilizer Plants; Final Guideline Document Availability,'' 42 FR 12,022 (Mar. 1, 1977); ''Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist,'' 42 FR 55,796 (Oct. 18, 1977); ''Kraft Pulp Mills, Notice of Availability of Final Guideline Document,'' 44 FR 29,828 (May 22, 1979); ''Primary Aluminum Plants; Availability of Final Guideline Document,'' 45 FR 26,294 (Apr. 17, 1980); ''Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule,'' 61 FR 9905 (Mar. 12, 1996).

any necessary compensating emission reductions), as part of the state's CAA section 111(d) plan submission. The agency requests comment on its interpretation.

c. Relationship to State Emission Performance Goals and Timing of Achievement

The EPA also believes that, because of the way the state-specific goals have been developed in these proposed guidelines, remaining useful life and other facility-specific considerations should not affect the determination of a state's rate-based or mass-based emission performance goal or the state's obligation to develop and submit an approvable CAA section 111(d) plan that achieves that goal by the applicable deadline.

Under the proposed guideline, states would have the flexibility to adopt a state plan that relies on emission-reducing requirements that do not require affected EGUs with a short remaining useful life to make major capital expenditures [305] or incur unreasonable costs. Indeed, the EPA's proposal would provide states with broad flexibility regarding ways to improve emission performance through utilizing the emissions reduction methods represented by the four ''building blocks.''

We also note that a state is not required to achieve the same level of emission reductions with respect to any one building block as assumed in the EPA's BSER analysis. If a state prefers not to attempt to achieve the level of performance estimated by the EPA for a particular building block, it can compensate through over-achievement in another one, or employ other compliance approaches not factored into the state-specific goal at all. The EPA has estimated reasonable rather than maximum possible implementation levels for each building block in order to establish overall state goals that are achievable/while allowing states to take advantage of the flexibility to pursue some building blocks more aggressively, and others less aggressively, than is reflected in the goal computations, according to each state's needs and preferences.

Of the four building blocks considered by the EPA in developing state goals, only the first block, heat rate improvements, involves capital investments at the affected EGUs which, if mandated by a state rule, might give rise to remaining useful life considerations at a particular facility. The other building blocks—re-dispatch among affected sources, addition of new generating capacity, and improvement in end-use energy efficiency—do not generally involve capital investments by the owner/operator at an affected EGU.

In the case of heat rate improvements at affected EGUs, states can choose whether to require a greater or lesser degree of heat rate improvement than the 6 percent improvement assumed in the EPA's proposed BSER determination, either because of the remaining useful life of one or more EGUs, other source-specific factors that the state deemed appropriate to consider, or any other relevant reasons. The agency also notes that any capital expenditures would be much smaller than capital expenditures required for example, for purchase and installation of scrubbers to remove sulfur dioxide; a fleet-wide average cost for heat rate improvements at coal-fired generating units is $100/kW, compared with a typical SO_2 scrubber cost of $500/kw (costs vary with unit size).[306] In addition, the proposed guideline allows states to regulate affected EGUs through flexible regulatory approaches that do not require affected EGUs to incur large capital costs (e.g., averaging and trading programs). Under the EPA's proposed approach—establishing state goals and providing states with flexibility in plan design—states have flexibility to make exactly the kind of judgments necessary to avoid requirements that would result in stranded assets.

Remaining useful life and other factors, because of their facility-specific nature, are potentially relevant in determining requirements that are directly applicable to affected EGUs. For all of the reasons above, the agency believes that the issue of remaining useful life will arise infrequently in the development of state plans to limit CO_2 emissions from affected existing EGUs. Even if relief is due a particular facility, the state has an available toolbox of emission reduction methods that it can use to develop a section 111(d) plan that meets its emissions performance goal on time. The EPA therefore proposes that the remaining useful life of affected EGUs, and the other facility-specific factors identified in the existing implementing regulations, should not be considered as a basis for adjusting a state emission performance goal or for relieving a state of its obligation to develop and submit an approvable plan that achieves that goal on time. The agency solicits comment on this position.

10. Design, Equipment, Work Practice, or Operational standards

In this section, we discuss whether state plans may include design, equipment, work practice, or operational standards.

CAA section 111(h)(1) authorizes the Administrator to promulgate ''a design, equipment, work practice, or operational standard, or combination thereof,'' if in his or her judgment, ''it is not feasible to prescribe or enforce a standard of performance.'' CAA section 111(h)(2) provides the circumstances under which prescribing or enforcing a standard of performance is ''not feasible'': generally, when the pollutant cannot be emitted through a conveyance designed to emit or capture the pollutant, or when there is no practicable measurement methodology for the particular class of sources. Other provisions in section 111(h) further provide that a design, equipment, work practice, or operational standard (i) must ''be promulgated in the form of a standard of performance whenever it becomes feasible'' to do so,[307] and (ii) must ''be treated as a standard of performance'' for purposes of, in general, the CAA.[308]

As noted above, CAA section 111(d) requires that state plans ''establish[] standards of performance'' as well as ''provide[] for the implementation and enforcement of such standards of performance.'' CAA section 111(d) is silent as to whether (i) states may include design, equipment, work practice, or operational standards, or (ii) they may include those types of standards, but only under the limited circumstances described in section 111(h) (i.e., when it is ''not feasible'' to prescribe or enforce a standard of performance). Similarly, section 111(h) applies by its terms when the Administrator is authorized to prescribe standards of performance (which would include rulemaking under CAA section 111(b)), but is silent as to whether it

[305] The agency requests comment on whether there are circumstances other than a major capital investment that could lead to a prospective state plan imposing unreasonable costs considering a facility's remaining useful life. Where annual costs predominate and/or capital costs do not constitute a major expense, the EPA believes that the remaining useful life of an affected EGU will not significantly affect its annualized cost of control and therefore should not be a factor in determining control requirements for the EGU.

[306] Heat rate improvement methods and related capital costs are discussed in the GHG Abatement Measures TSD; SO_2 scrubber capital costs are from the documentation for the EPA's IPM Base Case v5.13, Chapter 5, Table 5–3, available at *http://www.epa.gov/powersectormodeling/BaseCasev513.html*

[307] CAA section 111(h)(4).

[308] CAA section 111(h)(5).

applies to state plans under CAA section 111(d).[309]

We invite consideration of the proper interpretation of CAA sections 111(d) and (h), under either *Chevron* step 1 or step 2, specifically: (i) Do the provisions of section 111(d) preclude state plans from including ''design, equipment, work practice, or operational standard[s]'' unless those things can be considered ''standards of performance'' or as providing for the implementation and enforcement of such standards? As a related matter, do the references to ''standard[s] of performance'' in CAA section 111(h) indicate that design, equipment, work practice, or operational standards cannot be considered ''standards of performance?'' (ii) Alternatively, are state plans authorized to include those design, equipment, work practice, or operational standards, but only under the limited circumstances described in CAA section 111(h) relating to infeasibility? (iii) As another alternative, are state plans authorized to include design, equipment, work practice, or operational standards under all circumstances, so that the limits of CAA section 111(h) do not apply? Finally, to the extent there is legal uncertainty over whether, and under what circumstances, state plans may include those standards, should the EPA authorize state plans to include them, on the understanding that if the Court invalidates the EPA's interpretation, states would be required to revise their plans accordingly without further rulemaking from the EPA?

11. Emissions Averaging and Trading

In this section, we discuss why CAA section 111(d) plans may include standards of performance that authorize emissions averaging and trading.

CAA section 111(d) authorizes state plans to include ''standards of performance'' and measures that implement and enforce those standards of performance. CAA section 111(a)(1) defines a ''standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction . . . adequately demonstrated.'' CAA section 302 contains a set of definitions that apply ''[w]hen used in [the Clean Air Act],'' including subsection (l), which provides a separate definition of ''standard of performance'' as ''a requirement of continuous emission reduction. . .''

The EPA proposes that the definition of ''standard of performance'' is broad enough to incorporate emissions averaging and trading provisions, including both emission rate programs, in which sources may average or trade those rates, and mass emission limit programs, in which sources may buy and sell mass emission allowances (and, under certain circumstances, offsets).[310] The term ''standard'' in the phrase ''standard for emissions of air pollutants'' is not defined in the CAA. As the Supreme Court noted in a CAA case, a ''standard'' is simply ''that which 'is established by authority, custom, or general consent, as a model or example; criterion; test.' '' [311] A tradable emission rate or a tradable mass limit is a ''standard for emissions of air pollutants'' because it establishes an emissions limit for a source's air pollutants, and as a result, qualifies as a ''criterion'' or ''test'' for those air pollutants.

Moreover, although there may be doubt that the definition of ''standard of performance'' in CAA section 302(l) applies to CAA section 111(d) in light of the fact that the definition of the same term in CAA section 111(a)(1) is more specific, even if the CAA section 302(l) definition does apply, an averaging or trading requirement qualifies as a ''continuous emission reduction'' because, in the case of a tradable emission rate, the rate is applicable at all times, and, in the case of a tradable mass limit, the source is always under the obligation that its emissions be covered by allowances.

It should be noted that the EPA has promulgated two other CAA section 111(d) rulemakings that authorized state plans to include emissions averaging or trading.[312]

G. Additional Factors That Can Help State Meet Their CO_2 Emission Performance Goals

A resource available from the EPA for states pursuing market-based approaches is the EPA's data and experience in support of state trading programs and emissions data collection. For states needing technical assistance with data or operation of market-based programs, existing EPA data systems are a resource that have been used to collect emissions data, track allowances and transfers, and determine compliance for state programs. For example, New Hampshire was part of the Ozone Transport Commission (OTC) trading program but was not included in the NOx SIP Call. Because the state wanted its sources to continue to participate in a state trading program, the EPA operated the emissions trading program for New Hampshire sources, from allocating allowances to compliance determination.

Additionally, as noted elsewhere in this preamble, more than 25 states have mandatory renewable portfolio standards, and other states have voluntary renewable programs and goals. There is considerable diversity among the states in the scope and coverage of these standards, in particular in how renewable resources are defined. At the federal level, the EPA has considered the greenhouse gas implications related to biomass use at stationary sources through several actions, including a call for information from stakeholders and the development and review of the ''Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources,'' issued in September 2011. That study was reviewed by the EPA's Science Advisory Board in 2011 and 2012 and the agency continues to assess the framework and consider the latest scientific analyses and technical input received from stakeholders. The EPA expects that the framework, when finalized, will be a resource that could help inform states in the development of their CAA section 111(d) plans.

H. Resources for States To Consider in Developing Their Plans

As part of the stakeholder outreach process, the EPA asked states what the agency could do to facilitate state plan development and implementation. Some states indicated that they wanted the EPA to create resources to assist with state plan development, especially resources related to accounting for end-use energy efficiency and renewable energy (EE/RE) in state plans. They requested clear methodologies for

[309] It should be noted that section 111(b)(5), which concerns controls promulgated by the Administrator for new and modified sources, does refer to section 111(h).

[310] Typically, in a mass emission limit trading program, sources are required to obtain an allowance for each measure (e.g., ton) of air pollutant they emit. The acid rain program under Title IV of the CAA is an example of this type of trading program.

[311] *Engine Mfrs. Ass'n* v. *South Coast Air Quality Mgmt. Dist.,* 541 U.S. 246, 252–53 (2004) (quoting *Webster's Second International Dictionary,* at 2455 (1945))

[312] *See* ''Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, Final Rule,'' 70 FR 28,606 (May 18, 2005) [also known as the Clean Air Mercury Rule, or ''CAMR''], *vacated on other grounds by New Jersey* v. *EPA,* 517 F.3d 574 (D.C. Cir. 2008), *cert denied sub nom. Util. Air Reg. Grp.* v. *New Jersey,* 555 U.S. 1169 (2009); ''Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources; Municipal Waste Combustors,'' 60 FR 65,387 (Dec. 19, 1995) (trading rules codified in 40 CFR 60.33b(d)(1)–(2)).

measuring EE/RE policies and programs, so that these could be included as part of their compliance strategies. Stakeholders said that these tools and metrics should build upon the EPA's ''Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans,''[313] as well as the State Energy Efficiency Action Network's ''Energy Efficiency Program Impact Evaluation Guide.''[314] The EPA also heard that states would like examples of effective state policies and programs.

As a result of this feedback, in consultation with U.S. Department of Energy and other federal agencies, the EPA has developed a toolbox of decision support resources and is making that available at a dedicated Web site: *http://www2.epa.gov/www2.epa.gov/cleanpowerplantoolbox.* Current resources on the site focus on approaches states and other entities have already taken that reduce CO_2 emissions from the electric utility sector.

For the final rulemaking, the EPA plans to organize resources on the Web site around the following two categories: State plan guidance and state plan decision support. The state plan guidance section will serve as a central repository for the final emission guidelines, regulatory impact analysis, technical support documents, and other supporting materials. The state plan decision support section will include information to help states evaluate different approaches and measures they might consider as they initiate plan development. This section will include, for example, a summary of existing state climate and EE/RE policies and programs,[315] National Action Plan for Energy Efficiency (Action Plan),[316] information on electric utility actions that reduce CO_2, and tools and information to assist with translating energy savings into emission reductions.

We note that our inclusion of a measure in the toolbox does not mean that a state plan must include that measure. In fact, inclusion of measures provided at the Web site does not necessarily imply the approvability of an approach or method for use in a state plan. States will need to demonstrate that any measure included in a state plan meets all relevant approvability criteria and adequately addresses elements of the plan components discussed in Section VIII of this preamble.

The EPA solicits comment on this approach and the information currently included, and planned for inclusion, in the Decision Support Toolbox.

IX. Implications for Other EPA Programs and Rules

A. Implications for New Source Review Program

The new source review (NSR) program is a preconstruction permitting program that requires major stationary sources of air pollution to obtain permits prior to beginning construction. The requirements of the NSR program apply both to new construction and to modifications of existing major sources. Generally, a source triggers these permitting requirements as a result of a modification when it undertakes a physical or operational change that results in a significant emission increase and a net emissions increase. NSR regulations define what constitutes a significant net emissions increase, and the concept is pollutant-specific. For GHG emissions, the PSD applicability analysis is described in the Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (FR 75 31514, June 3, 2010). As a general matter, a modifying major stationary source would trigger PSD permitting requirements for GHGs if it emits GHGs in excess of 100,000 tons per year (tpy) of carbon dioxide equivalents (CO_2e), and it undergoes a change or change in the method of operation (modification) resulting in an emissions increase of 75,000 tpy CO_2e as well as an increase on a mass basis. Once it has been determined that a change triggers the requirements of the NSR program, the source must obtain a permit prior to making the change. The pollutant(s) at issue and the air quality designation of the area where the facility is located or proposed to be built determine the specific permitting requirements.

As part of its CAA section 111(d) plan, a state may impose requirements that require an affected EGU to undertake a physical or operational change to improve the unit's efficiency that results in an increase in the unit's dispatch and an increase in the unit's annual emissions. If the emissions increase associated with the unit's changes exceeds the thresholds in the NSR regulations discussed above for one or more regulated NSR pollutants, including the netting analysis, the changes would trigger NSR.

While there may be instances in which an NSR permit would be required, we expect those situations to be few. As previously discussed in this preamble, states have considerable flexibility in selecting varied measures as they develop their plans to meet the goals of the emissions guidelines. One of these flexibilities is the ability of the state to establish the standards of performance in their CAA section 111(d) plans in such a way so that their affected sources, in complying with those standards, in fact would not have emissions increases that trigger NSR. To achieve this, the state would need to conduct an analysis consistent with the NSR regulatory requirements that supports its determination that as long as affected sources comply with the standards of performance in their CAA section 111(d) plan, the source's emissions would not increase in a way that trigger NSR requirements.

For example, a state could decide to adjust its demand side measures or increase reliance on renewable energy as a way of reducing the future emissions of an affected source initially predicted (without such alterations) to increase its emissions as a result of a CAA section 111(d) plan requirement. In other words, a state plan's incorporation of expanded use of cleaner generation or demand-side measures could yield the result that units that would otherwise be projected to trigger NSR through a physical change that might result in increased dispatch would not, in fact, increase their emissions, due to reduced demand for their operation. The state could also, as part of its CAA section 111(d) plan, develop conditions for a source expected to trigger NSR that would limit the unit's ability to move up in the dispatch enough to result in a significant net emissions increase that would trigger NSR (effectively establishing a synthetic minor limit).[317]

We request comment on whether, with adequate record support, the state plan could include a provision, based on underlying analysis, stating that an affected source that complies with its applicable standard would be treated as not increasing its emissions, and if so, whether such a provision would mean that, as a matter of law, the source's actions to comply with its standard

[313] *http://epa.gov/airquality/eere/.*

[314] *http://www1.eere.energy.gov/seeaction/index.html.*

[315] Appendix, State Plan Considerations TSD.

[316] *http://www.epa.gov/cleanenergy/energy-programs/suca/resources.html.*

[317] Certain stationary sources that emit or have the potential to emit a pollutant at a level that is equal to or greater than specified thresholds are subject to major source requirements. *See, e.g.,* CAA §§ 165(a)(1), 169(1), 501(2), 502(a). A synthetic minor limitation is a legally and practicably enforceable restriction that has the effect of limiting emissions below the relevant level and that a source voluntarily obtains to avoid major stationary source requirements, such as the PSD or title V permitting programs. *See, e.g.,* 40 CFR 52.21(b)(4), 51.166(b)(4), 70.2 (definition of ''potential to emit'').

would not subject the source to NSR. We also seek comment on the level of analysis that would be required to support a state's determination that sources will not trigger NSR when complying with the standards of performance included in the state's CAA section 111(d) plan and the type of plan requirements, if any, that would need to be included in the state's plan.

As a result of such flexibility and anticipated state involvement, we expect that a limited number of affected sources would trigger NSR when states implement their plans.

B. Implications for Title V Program

The preamble to the re-proposed EGU NSPS (70 FR 1429–1519; January 8, 2014) explained that regulating GHGs for the first time under section 111 of the CAA would make GHGs ''regulated air pollutants'' for the first time under the operating permit regulations of 40 CFR parts 70 and 71. This would result in GHGs becoming ''fee pollutants'' in certain state part 70 permit programs and in the EPA's part 71 permit program, thus requiring the collection of fees for GHG emissions in these programs. Where title V fees would be required for GHGs, they would typically be charged at the same rate ($ per ton of pollutant) as all other fee pollutants. This would likely result in excessive and unnecessary fees being charged to subject sources. To avoid this situation, we proposed to exempt GHGs from the fee rates in effect for other fee pollutants, while proposing an alternative fee that would be much lower than the fee charged to other fee pollutants, yet sufficient to cover the costs of addressing GHGs in operating permits.

This title V fee issue is a one-time occurrence resulting from the promulgation of the first CAA section 111 standard to regulate GHGs (the EGU NSPS for new sources) and is not an issue for any other subsequent CAA section 111 regulations, so there is no need to address any title V fee issues in this proposal. Thus, we are not re-visiting these title V fee issues in this proposal, and we are not proposing any additional revisions to any title V regulations as part of this action.

The title V regulations require each permit to include emission limitations and standards, including operational requirements and limitations that assure compliance with all applicable requirements. Requirements resulting from this rule that are imposed on affected EGUs or any other potentially affected entities that have title V operating permits are applicable requirements under the title V regulations and would need to be incorporated into the source's title V permit in accordance with the schedule established in the title V regulations. For example, if the permit has a remaining life of three years or more, a permit reopening to incorporate the newly applicable requirement shall be completed no later than 18 months after promulgation of the applicable requirement. If the permit has a remaining life of less than three years, the newly applicable requirement must be incorporated at permit renewal.

C. Interactions With Other EPA Rules

Existing fossil fuel-fired EGUs, such as those covered in this proposal, are or will be potentially impacted by several other recently finalized or proposed EPA rules.[318] On February 16, 2012, the EPA issued the mercury and air toxics standards (MATS) rule (77 FR 9304) to reduce emissions of toxic air pollutants from new and existing coal- and oil-fired EGUs. The MATS rule will reduce emissions of heavy metals, including mercury (Hg), arsenic (As), chromium (Cr), and nickel (Ni); and acid gases, including hydrochloric acid (HCl) and hydrofluoric acid (HF). These toxic air pollutants, also known as hazardous air pollutants or air toxics, are known or suspected of causing damage to the nervous system, cancer, and other serious health effects. The MATS rule will also reduce SO_2 and fine particle pollution, which will reduce particle concentrations in the air and prevent thousands of premature deaths and tens of thousands of heart attacks, bronchitis cases and asthma episodes.

The EPA is closely monitoring MATS compliance and finds that the industry is making substantial progress. Plant owners are moving proactively to install controls that will achieve the MATS performance standards. Certain units, especially those that operate infrequently, may be considered not worth investing in given today's electricity market, and those are closing.

Existing sources subject to the MATS rule are given until April 16, 2015 to comply with the rule's requirements. The final MATS rule provided a foundation on which states and other permitting authorities could rely in granting an additional, fourth year for compliance provided for by the CAA. States report that these fourth year extensions are being granted. In addition, the EPA issued an enforcement policy that provides a clear pathway for reliability-critical units to receive an administrative order that includes a compliance schedule of up to an additional year, if it is needed to ensure electricity reliability.

On May 19, 2014, the EPA issued a final rule under section 316(b) of the Clean Water Act (33 U.S.C. 1326(b)) (referred to hereinafter as the 316(b) rule).[319] This rule establishes new standards to reduce injury and death of fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities.[320] The 316(b) rule subjects existing power plants and manufacturing facilities that withdraw in excess of 2 million gallons per day (MGD) of cooling water, and use at least 25 percent of that water for cooling purposes, to a national standard designed to reduce the number of fish destroyed through impingement and a national standard for establishing entrainment reduction requirements. All facilities subject to the rule must submit information on their operations for use by the permit authority in determining 316(b) permit conditions. Certain plants that withdraw very large volumes of water will also be required to conduct additional studies for use by the permit authority in determining the site-specific entrainment reduction measures for such facilities. The rule provides significant flexibility for compliance with the impingement standards and, as a result, is not projected to impose a substantial cost burden on affected facilities. With respect to entrainment, the rule calls upon the permitting authority to in establishing appropriate entrainment reduction measures, taking into account, among other factors, compliance costs, facility reliability and grid reliability. Existing sources subject to the 316(b) rule are required to comply with the impingement requirements as soon as practicable after the entrainment requirements are determined. They must comply with applicable site-specific entrainment reduction controls based on the schedule of requirements established by the permitting authority.

The EPA is also reviewing public comments and working to finalize two proposed rules which will also impact

[318] We discuss other rulemakings solely for background purposes. The effort to coordinate rulemakings is not a defense to a violation of the CAA. Sources cannot defer compliance with existing requirements because of other upcoming regulations.

[319] The pre-publication version of the final rule is available at: *http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/#final.*

[320] CWA section 316(b) provides that standards applicable to point sources under sections 301 and 306 of the Act must require that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

existing fossil fuel-fired EGUs: The steam electric effluent limitation guidelines (SE ELG) rule and the coal combustion residuals (CCR) rule. These proposed rules are summarized below.

On June 7, 2013 (78 FR 34432), the EPA proposed the SE ELG rule to strengthen the controls on discharges from certain steam electric power plants by revising technology-based effluent limitations guidelines and standards for the steam electric power generating point source category. The current regulations, which were last updated in 1982, do not adequately address the toxic pollutants discharged from the electric power industry, nor have they kept pace with process changes that have occurred over the last three decades. Existing steam electric power plants currently contribute 50–60 percent of all toxic pollutants discharged to surface waters by all industrial categories regulated in the United States under the CWA. Furthermore, power plant discharges to surface waters are expected to increase as pollutants are increasingly captured by air pollution controls and transferred to wastewater discharges. This proposed regulation, which includes new requirements for both existing and new generating units, would reduce the amount of toxic metals and other pollutants discharged to surface waters from power plants.

On June 21, 2010 (75 FR 35128), the EPA proposed the CCR rule, which co-proposed two approaches to regulating the disposal of coal combustion residuals (CCRs) generated by electric utilities and independent power producers. CCRs are residues from the combustion of coal in steam electric power plants and include materials such as coal ash (fly ash and bottom ash) and flue gas desulfurization (FGD) wastes. Under one proposed approach, the EPA would list these residuals as ''special wastes,'' when destined for disposal in landfills or surface impoundments, and would apply the existing regulatory requirements established under Subtitle C of RCRA to such wastes. Under the second proposed approach, the EPA would establish new regulations applicable specifically to CCRs under subtitle D of RCRA, the section of the statute applicable to solid (i.e., non-hazardous) wastes. Under both approaches, CCRs that are beneficially used would remain exempt under the Bevill exclusion.[321] While the EPA still is evaluating all the available information and comments, and while a final risk assessment for the CCR rule has not yet been completed, reliance on data and analyses discussed in the preamble to the recent SE ELG proposal might have the potential to lower the CCR rule risk assessment results by as much as an order of magnitude. If this proves to be the case, the EPA's current thinking is that the revised risks, coupled with the ELG requirements that the agency might promulgate, and the increased federal oversight such requirements could achieve, could provide strong support for a conclusion that regulation of CCR disposal under RCRA Subtitle D would be adequate.[322] The EPA is under a court-ordered deadline to complete the CCR rulemaking by December 19, 2014.

The EPA recognizes the importance of assuring that each of the rules described above can achieve its intended environmental objectives in a commonsense, cost-effective manner, consistent with underlying statutory requirements, and while assuring a reliable power system. Executive Order (EO) 13563, ''Improving Regulation and Regulatory Review,'' issued on January 18, 2011, states that ''[i]n developing regulatory actions and identifying appropriate approaches, each agency shall attempt to promote . . . coordination, simplification, and harmonization. Each agency shall also seek to identify, as appropriate, means to achieve regulatory goals that are designed to promote innovation.'' Within the EPA, we are paying careful attention to the interrelatedness and potential impacts on the industry, reliability and cost that these various rulemakings can have.

As discussed in Sections VII and VIII of this preamble, the EPA is proposing to give states broad flexibility in developing approvable plans under CAA section 111(d), including the ability to adopt rate-based or mass-based emission performance goals, and to rely on a wide variety of CO_2 emission reduction measures. The EPA is also proposing to give states considerable flexibility with respect to the timeframes for plan development and implementation, with up to two or three years permitted for final plans to be submitted after the proposed GHG emission guidelines are finalized, and up to fifteen years for all emission reduction measures to be fully implemented. In light of these flexibilities, we believe that states will have ample opportunity, when developing and implementing their CAA section 111(d) plans, to coordinate their response to this requirement with source and state responses to any obligations that may be applicable to affected EGUs as a result of the MATS, 316(b), SE ELG and CCR rules—all of which are or will be final rules before this rulemaking is finalized—and to do so in a manner that will help reduce cost and ensure reliability, while also ensuring that all applicable environmental requirements are met.[323]

The EPA is also endeavoring to enable EGUs to comply with applicable obligations under other power sector rules as efficiently as possible (e.g., by facilitating their ability to coordinate planning and investment decisions with respect to those rules) and, where possible, implement integrated compliance strategies. For example, in the proposed SE ELG rule, the EPA describes its current thinking on how it might effectively harmonize the potential requirements of that rule with the requirements of the final CCR rule, to the extent that both rules may regulate or affect the disposal of coal combustion wastes to and from surface impoundments at power plants.[324] The EPA's goal in exploring how it might harmonize the SE ELG and CCR rules is to minimize the overall complexity of the two regulatory structures and avoid creating unnecessary burdens.[325]

[321] Beneficial use involves the reuse of CCRs in a product to replace virgin raw materials that would otherwise be obtained through extraction. The EPA encourages the beneficial use of CCRs in an appropriate and protective manner, because this practice can produce environmental, economic, and performance benefits. The Agency recently evaluated the environmental impacts associated with encapsulated beneficial uses of fly ash used as a direct substitute for Portland cement in concrete, and FGD gypsum used as a replacement for mined gypsum in wallboard. The EPA concluded that the beneficial use of CCRs in concrete and wallboard is appropriate because the environmental releases of constituents of potential concern (COPC) during use by the consumer are comparable to or lower than those from analogous non-CCR products, or are at or below relevant regulatory and health-based benchmarks for human and ecological receptors. *See* U.S. Environmental Protection Agency, *Coal Combustion Residual Beneficial Use Evaluation: Fly Ash Concrete and FGD Gypsum Wallboard* (2014).

[322] U.S. EPA. September 2013. Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units. EPA–452/R–13–003. Available at *http://www2.epa.gov/sites/production/files/2013–09/documents/20130920proposalria.pdf.*

[323] It should be noted that regulatory obligations imposed upon states and sources operate independently under different statutes and sections of statutes; the EPA expects that states and sources will take advantage of available flexibilities as appropriate, but will comply with all relevant legal requirements.

[324] See: **Federal Register** Vol. 78, No. 110; June 7, 2013. Page 34441.

[325] In considering how to coordinate the potential requirements between the SE ELG and CCR rules, the EPA stated that it is guided by the following policy considerations: First and foremost, the EPA intends to ensure that its statutory responsibilities to restore and maintain water quality under the CWA and to protect human health and the environment under RCRA are fulfilled. At the same time, the EPA would seek to minimize the potential

In addition to the power sector rules discussed above, the development of SIPs for criteria pollutants ($PM_{2.5}$, ozone and SO_2) and regional haze may also have implications for existing fossil-fired EGUs.

On June 6, 2013, the EPA proposed an implementation rule for the 2008 ozone National Ambient Air Quality Standards (NAAQS), to provide rules and guidance to states on the development of approvable state implementation plans (SIPs), including SIPs under CAA section 110 (infrastructure SIPs) and section 182 (ozone nonattainment SIPs). This rule addresses the statutory requirements for areas that the EPA has designated as nonattainment for the 2008 ozone standard. The agency is currently working to finalize that rule. The EPA is also working on a proposed transport rule that would identify the obligations of upwind states that contribute to those downwind state ozone nonattainment areas. This rule is scheduled for proposal in 2014 and to be finalized by 2015.

The EPA is developing a proposed implementation rule to provide guidance to states on the development of SIPs for the 2012 $PM_{2.5}$ NAAQS.

The SO_2 NAAQS was revised in June 2010 to protect public health from the short-term effects of SO_2 exposure. In July 2013, the EPA designated 29 areas in 16 states as nonattainment for the SO_2 NAAQS. The EPA based these nonattainment designations on the most recent set of certified air quality monitoring data as well as an assessment of nearby emission sources and weather patterns that contribute to the monitored levels. The EPA intends to address the designations for all other areas in separate actions in the future [326]. The EPA has proposed the data requirements rule for the 1-hour SO_2 NAAQS to require states to characterize air quality more extensively using ambient monitoring or air quality modeling approaches.

The EPA requires SIP updates every 10 years for regional haze, as required by the EPA's Regional Haze Rule which was promulgated in 1999. The next 10-year SIP revision for regional haze, covering the time period through 2028, is due from each state by July 2018. Each SIP must provide for reasonable progress towards visibility improvement in protected scenic areas.

The development of these SIPs may, where applicable, have significant implications for existing fossil fuel-fired EGUs, as well as for the states that are responsible for developing them. The timeframes for submittal of SIPs for the various programs and the timeframes we are proposing for submittal of the CAA section 111(d) state plans will allow considerable time for coordination by states in the development of their respective plans. The EPA is willing to work with states to assist them in coordinating their efforts across these planning processes. The EPA believes that CAA section 111(d) efforts and actions will tend to contribute to overall air quality improvements and thus should be complementary to criteria pollutant and regional haze SIP efforts.

In light of the broad flexibilities we are proposing in this action, we believe that states will have ample opportunity to design CAA section 111(d) plans that use innovative, cost-effective regulatory strategies and that spark investment and innovation across a wide variety of clean energy technologies. We also believe that the broad flexibilities we are proposing in this action will enable states and affected EGUs to build on their longstanding, successful records of complying with multiple CAA, CWA, and other environmental requirements, while assuring an adequate, affordable, and reliable supply of electricity.

X. Impacts of the Proposed Action [327]

A. What are the air impacts?

The EPA anticipates significant emission reductions under the proposed guidelines for the power sector. CO_2 emissions are projected to be reduced when compared to 2005 emissions, by 26 percent to 27 percent in 2020 and about 30 percent in 2030 under Option 1. Option 2 reflects reductions of about 23 percent in 2020 and 23 percent to 24 percent in 2025 when compared to CO_2 emissions in 2005. The guidelines are projected to result in substantial co-benefits through reductions of SO_2, $PM_{2.5}$ and NOx that will have direct public health benefits by lowering ambient levels of these pollutants and ozone. Tables 10 and 11 show expected CO_2 and other air pollutant emission reductions in the base case, with the proposed Option 1 for 2020, 2025, and 2030 and regulatory alternative Option 2, for 2020 and 2025.

TABLE 10—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS WITH OPTION 1

	CO_2 (million metric tons)	SO_2 (thousands of tons)	NO_X (thousands of tons)	$PM_{2.5}$ (thousands of tons)
2020 Regional Compliance Approach:				
Base Case Proposed	2,161	1,476	1,559	212
Guidelines:	1,790	1,184	1,213	156
Emission Reductions	371	292	345	56
2025 Regional Compliance Approach:				
Base Case Proposed	2,231	1,515	1,587	209
Guidelines:	1,730	1,120	1,166	150

for overlapping requirements to avoid imposing any unnecessary burdens on regulated entities and to facilitate implementation and minimize the overall complexity of the regulatory structure under which facilities must operate. Based on these considerations, the EPA stated that it is exploring two primary means of integrating the two rules: (1) Through coordinating the design of any final substantive CCR regulatory requirements, and (2) through coordination of the timing and implementation of final rule requirements to provide facilities with a reasonable timeline for implementation that allows for coordinated planning and protects electricity reliability for consumers.

[326] The EPA has developed a comprehensive implementation strategy for these future actions that focuses resources on identifying and addressing unhealthy levels of SO_2 in areas where people are most likely to be exposed to violations of the standard. The strategy is available at: *http://www.epa.gov/airquality/sulfurdioxide/implement.html.*

[327] The impacts presented in this section of the preamble represent an illustrative implementation of the guidelines. As states implement the proposed guidelines, they have sufficient flexibility to adopt different state-level or regional approaches that may yield different costs, benefits, and environmental impacts. For example, states may use the flexibilities described in these guidelines to find approaches that are more cost effective for their particular state or choose approaches that shift the balance of co-benefits and impacts to match broader state priorities.

TABLE 10—SUMMARY OF CO_2 AND OTHER AIR POLLUTANT EMISSION REDUCTIONS WITH OPTION 1—Continued

	CO_2 (million metric tons)	SO_2 (thousands of tons)	NO_X (thousands of tons)	$PM_{2.5}$ (thousands of tons)
Emission Reductions	501	395	421	59
2030 Regional Compliance Approach:				
Base Case Proposed	2,256	1,530	1,537	198
Guidelines:	1,711	1,106	1,131	144
Emission Reductions	545	424	407	54
2020 State Compliance Approach:				
Base Case Proposed	2,161	1,476	1,559	212
Guidelines:	1,777	1,140	1,191	154
Emission Reductions	383	335	367	58
2025 State Compliance Approach:				
Base Case Proposed	2,231	1,515	1,587	209
Guidelines:	1,724	1,090	1,151	145
Emission Reductions	506	425	436	63
2030 State Compliance Approach:				
Base Case Proposed	2,256	1,530	1,537	198
Guidelines:	1,701	1,059	1,109	142
Emission Reductions	555	471	428	56

Source: Integrated Planning Model, 2014.

TABLE 11—SUMMARY OF CO_2 AND AIR POLLUTANT EMISSION REDUCTIONS WITH OPTION 2

	CO_2 (million metric tons)	SO_2 (thousands of tons)	NO_X (thousands of tons)	$PM_{2.5}$ (thousands of tons)
2020 Regional Compliance Approach:				
Base Case	2,161	1,476	1,559	212
Option 2	1,878	1,231	1,290	166
Emission Reductions	283	244	268	46
2025 Regional Compliance Approach:				
Base Case	2,231	1,515	1,587	209
Option 2	1,862	1,218	1,279	165
Emission Reductions	368	297	309	44
2020 State Compliance Approach:				
Base Case	2,161	1,476	1,559	212
Option 2	1,866	1,208	1,277	163
Emission Reductions	295	267	281	49
2025 State Compliance Approach:				
Base Case	2,231	1,515	1,587	209
Option 2	1,855	1,188	1,271	161
Emission Reductions	376	327	317	48

Source: Integrated Planning Model, 2014.

The reductions in these tables do not account for reductions in hazardous air pollutants (HAPs) that may occur as a result of this rule. For instance, the fine particulate reductions presented above do not reflect all of the reductions in many heavy metal particulates.

B. Comparison of Building Block Approaches

Though the EPA has determined that the 4-building block approach is the BSER, we did analyze the impacts of both a combination of building blocks 1 and 2 and the combination of all four building blocks. The analysis indicates that the combined strategies of heat rate improvements (building block 1) and re-dispatch (building block 2) would result in overall CO_2 emission reductions of approximately 22 percent in 2020 (compared to 2005 emissions and

assuming state-level compliance). This compares to expected CO_2 emission reductions of approximately 27 percent for the four-block BSER approach discussed below. The EPA analysis also estimates 24–32 GW of additional coal-fired EGU retirements in 2020 (compared to 46–49 GW for the four-block approach) and an additional 3–5 GW of oil/gas steam EGUs (compared to 16 GW for the four-block approach). For both the two-block and the four-block approach, a decrease in coal production and price is predicted in 2020. The decrease in production is predicted at 20–23 percent for the two-block approach, compared to a decrease of 25–27 percent for the four-block approach. A 12 percent decrease in coal prices is predicted for the two-block approach; while the four-block approach results in a 16 to 18 percent decrease. Under both approaches, the shifting in generation from higher-emitting steam EGUs to lower-emitting NGCC units results in an increase in natural gas production and price. The two-block approach results in a production increase of 19–22 percent and a price increase of 10–11 percent. The four-block approach results in a production increase of 12–14 percent and a price increase of 9–12 percent. Both the two-block and the four-block approaches result in construction of additional NGCC capacity by 2020, with 11–18 GW of new NGCC for the two-block approach and 20–22 GW of new NGCC capacity for the four-block approach. However, while the two-block approach results in 5–17 GW of new NGCC capacity in 2030, the four-block approach results in 32–35 GW less NGCC capacity in 2030 relative to the base case (due to increased use of renewable energy sources and decreased demand from implementation of demand side energy efficiency measures). Also, significantly, the two-block approach results in less than 500 MW of new renewable energy capacity; while the four-block option results in approximately 12 GW of new renewable generating capacity.

The EPA projects that the annual incremental compliance cost for the building block 1 and 2 approach is estimated to be $3.2 to $4.4 billion in 2020 and $6.8 to $9.8 billion (2011$) in 2030, excluding the costs associated with monitoring, reporting, and recordkeeping (MRR). This compares to costs excluding MRR of $5.4 to $7.4 billion in 2020 and $7.3 to $8.8 billion in 2030 for the proposed Option 1 (2011$) as discussed in Section X.E of this preamble.

The total combined climate benefits and health co-benefits for the building block 1 and 2 approach are estimated to be $21 to $40 billion in 2020 and $32 to $63 billion in 2030 (2011$ at a 3-percent discount rate [model average]). The net benefits are estimated to be $18 to $36 billion in 2020 and $25 to $53 billion in 2030 (2011$ at a 3-percent discount rate [model average]). For the purposes of this summary, we list the climate benefits associated with the marginal value of the model average at 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. These building block 1 and 2 benefit estimates compare to combined climate benefits and health co-benefits of $33 to $57 billion in 2020 and $55 to $93 billion in 2030 (2011$ at a 3-percent discount rate [model average]) for the proposed Option 1. Net benefits are estimated to be $27 to $50 billion in 2020 and $48 to $84 billion in 2030 (2011$ at a 3-percent discount rate [model average]) as discussed in Section X.G. and XI.A of this preamble.[328]

C. Endangered Species Act

Consistent with the requirements of section 7(a)(2) of the Endangered Species Act (ESA), the EPA has also considered the effects of this proposed rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed endangered or threatened species or designated critical habitat. Section 7(a)(2) of the ESA requires federal agencies, in consultation with the U.S. Fish and Wildlife Service (FWS) and/or the National Marine Fisheries Service, to ensure that actions they authorize, fund, or carry out are not likely to jeopardize the continued existence of federally listed endangered or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. 16 U.S.C. 1536(a)(2). Under relevant implementing regulations, section 7(a)(2) applies only to actions where there is discretionary federal involvement or control. 50 CFR 402.03. Further, under the regulations consultation is required only for actions that ''may affect'' listed species or designated critical habitat. 50 CFR § 402.14. Consultation is not required where the action has no effect on such species or habitat. Under this standard, it is the federal agency taking the action that evaluates the action and determines whether consultation is required. *See* 51 FR 19926, 19949 (June 3, 1986). Effects of an action include both the direct and indirect effects that will be added to the environmental baseline. 50 CFR 402.02. Indirect effects are those that are caused by the action, later in time, and are reasonably certain to occur. *Id.* To trigger a consultation requirement, there must thus be a causal connection between the federal action, the effect in question, and the listed species, and the effect must be reasonably certain to occur.

The EPA has considered the effects of this proposed rule and has reviewed applicable ESA regulations, case law, and guidance to determine what, if any, impact there may be to listed species or designated critical habitat for purposes of section 7(a)(2) consultation. The EPA notes that the projected environmental effects of this proposal are positive: reductions in overall GHG emissions, and reductions in PM and ozone-precursor emissions (SO_X and NO_X). With respect to the projected GHG emission reductions, the EPA does not believe that such reductions trigger ESA consultation requirements under section 7(a)(2). In reaching this conclusion, the EPA is mindful of significant legal and technical analysis undertaken by FWS and the U.S. Department of the Interior in the context of listing the polar bear as a threatened species under the ESA. In that context, in 2008, FWS and DOI expressed the view that the best scientific data available were insufficient to draw a causal connection between GHG emissions and effects on the species in its habitat.[329] The DOI Solicitor concluded that where the effect at issue is climate change, proposed actions involving GHG emissions cannot pass the ''may affect'' test of the section 7 regulations and thus are not subject to ESA consultation. The EPA has also previously considered issues relating to GHG emissions in connection with the requirements of ESA section 7(a)(2). Although the GHG emission reductions projected for this proposal are large (the highest estimate is reductions of 555 MMT of CO_2 in 2030—see Table 10 above), the EPA evaluated larger reductions in assessing this same issue in the context of the light duty vehicle GHG emission standards for model years 2012–2016 and 2017–2025. There the agency projected emission reductions roughly double and four times those projected

[328] Note that the health co-benefits and net benefits for the proposed Option 1 include PM co-benefits associated with directly emitted $PM_{2.5}$. In contrast, the building block 1 and 2 analysis does not include co-benefits related to directly emitted $PM_{2.5}$.

[329] *See, e.g.,* 73 FR 28212, 28300 (May 15, 2008); Memorandum from David Longly Bernhardt, Solicitor, U.S. Department of the Interior re: ''Guidance on the Applicability of the Endangered Species Act's Consultation Requirements to Proposed Actions Involving the Emission of Greenhouse Gases'' (Oct. 3, 2008).

here over the lifetimes of the model years in question [330] and, based on air quality modeling of potential environmental effects, concluded that ''EPA knows of no modeling tool which can link these small, time-attenuated changes in global metrics to particular effects on listed species in particular areas. Extrapolating from global metric to local effect with such small numbers, and accounting for further links in a causative chain, remain beyond current modeling capabilities.'' EPA, *Light Duty Vehicle Greenhouse Gas Standards and Corporate Average Fuel Economy Standards,* Response to Comment Document for Joint Rulemaking at 4–102 (Docket EPA–OAR–HQ–2009–4782). The EPA reached this conclusion after evaluating issues relating to potential improvements relevant to both temperature and oceanographic pH outputs. The EPA's ultimate finding was that ''any potential for a specific impact on listed species in their habitats associated with these very small changes in average global temperature and ocean pH is too remote to trigger the threshold for ESA section 7 (a)(2).'' *Id.* The EPA believes that the same conclusions apply to the present proposal, given that the projected CO_2 emission reductions are less than those projected for either of the light duty vehicle rules. *See, e.g., Ground Zero Center for Non-Violent Action* v. *U.S. Dept. of Navy,* 383 F. 3d 1082, 1091–92 (9th Cir. 2004) (where the likelihood of jeopardy to a species from a federal action is extremely remote, ESA does not require consultation).

With regard to non-GHG air emissions, the EPA is also projecting substantial reductions of SO_X and NO_X as a collateral consequence of this proposal. However, CAA section 111(d)(1) standards cannot directly control emissions of criteria pollutants. Consequently, CAA section 111(d) provides no discretion to adjust the standard based on potential impacts to endangered species of reduced criteria pollutant emissions. Section 7(a)(2) consultation thus is not required with respect to the projected reductions of criteria pollutant emissions. *See* 50 CFR 402.03; *see also, National Lime Ass'n* v. *EPA,* 233 F. 3d 625, 638–39 (D.C. Cir. 2000) (although CAA section 112(b)(2) prohibits the EPA from listing criteria pollutants as hazardous air pollutants, the EPA may use PM as a surrogate for metal hazardous air pollutants and reductions in PM do not constitute impermissible regulation of a criteria pollutant).

Moreover, there are substantial questions as to whether any potential for relevant effects results from any element of the proposed rule or would result instead from the separate actions of States establishing standards of performance for existing sources and implementing and enforcing those standards. *Cf. American Trucking Assn's* v. *EPA,* 175 F. 3d 1027, 1043–45 (D.C. Cir. 1999), *rev'd on different grounds sub nom., Whitman* v. *American Trucking Assn's,* 531 U.S. 457 (2000) (National Ambient Air Quality Standards have no economic impact, for purposes of Regulatory Flexibility Act, because impacts result from the actions of States through their development, implementation and enforcement of state implementation plans). Thus, for example, although questions may exist whether actions such as increased utilization of solar or wind power could have effects on listed species, the EPA believes that such effects (if any) would result from decisions and actions by states in developing, implementing and enforcing their plans. The precise steps States choose to take in that regard cannot be determined or ordered by this federal action, and they are not sufficiently certain to be attributable to this proposed rule for ESA purposes. Consequently, for this additional reason, the EPA does not believe that this proposed rule (if enacted) would have effects on listed species that would trigger the section 7 (a)(2) consultation requirement.

D. What are the energy impacts?

The proposed guidelines have important energy market implications. Under Option 1, average nationwide retail electricity prices are projected to increase by roughly 6 to 7 percent in 2020 relative to the base case, and by roughly 3 percent in 2030 (contiguous U.S.). Average monthly electricity bills are anticipated to increase by roughly 3 percent in 2020, but decline by approximately 9 percent by 2030. This is a result of the increasing penetration of demand-side programs that more than offset increased prices to end users by their expected savings from reduced electricity use.

The average delivered coal price to the power sector is projected to decrease by 16 to 17 percent in 2020 and roughly 18 percent in 2030, relative to the base case for Option 1. The EPA also projects that electric power sector-delivered natural gas prices will increase by 9 to 12 percent in 2020, with negligible changes in 2030. Natural gas use for electricity generation will increase by as much as 1.2 trillion cubic feet (TCF) in 2020 relative to the base case, and then begin to decline over time.

These figures reflect the EPA's illustrative modeling that presumes policies that lead to dispatch changes in 2020 and growing use of energy efficiency and renewable electricity generation out to 2029. If states make different policy choices, impacts could be different. For instance, if states implement renewable and/or energy efficiency policies on a more aggressive time-frame, impacts on natural gas and electricity prices would likely be less. Implementation of other measures not included in the EPA's BSER calculation or compliance modeling, such as nuclear uprates, transmission system improvements, use of energy storage technologies or retrofit CCS, could also mitigate gas price and/or electricity price impacts.

The EPA projects coal production for use by the power sector, a large component of total coal production, will decline by roughly 25 to 27 percent in 2020 from base case levels. The use of coal by the power sector will decrease roughly 30 to 32 percent in 2030. Renewable energy capacity is anticipated to increase by roughly 12 GW in 2020 and by 9 GW in 2030 under Option 1. Energy market impacts from the guidelines are discussed more extensively in the RIA found in the docket for this rulemaking.

E. What are the compliance costs?

The compliance costs of this proposed action are represented in this analysis as the change in electric power generation costs between the base case and the proposed rule in which states pursue a distinct set of strategies beyond the strategies taken in the base case to meet the terms of the EGU GHG emission guidelines, and include cost estimates for demand-side energy efficiency. The compliance assumptions—and, therefore, the projected compliance costs—set forth in this analysis are illustrative in nature and do not represent the full suite of compliance flexibilities states may ultimately pursue. These illustrative compliance scenarios are designed to reflect, to the extent possible, the scope and the nature of the proposed guidelines. However, there is considerable uncertainty with regards to the precise measures that states will adopt to meet the proposed requirements, because there are considerable flexibilities afforded to the states in developing their state plans.

The EPA projects that the annual incremental compliance cost of Option 1 is estimated to be between $5.5 and $7.5 billion in 2020 and between $7.3

[330] See 75 FR at 25438 Table I.C 2–4 (May 7, 2010); 77 FR at 62894 Table III–68 (Oct. 15, 2012).

and $8.8 billion (2011$) in 2030, including the costs associated with monitoring, reporting, and recordkeeping (MRR). The incremental compliance cost of Option 2 is estimated to be between $4.3 and $5.5 billion in 2020, including MRR costs. In 2025, the estimated compliance cost of Option 2 is estimated to be between $4.5 and $5.5 billion (with the assumed levels of end-use energy efficiency). These important dynamics are discussed in more detail in the RIA in the rulemaking docket. The annualized incremental cost is the projected additional cost of complying with the guidelines in the year analyzed, and includes the amortized cost of capital investment, needed new capacity, shifts between or amongst various fuels, deployment of energy efficiency programs, and other actions associated with compliance. MRR costs are estimated to be $68.3 million (2011$) in 2020 and $8.9 million in 2025 and 2030 for Option 1 and $68.3 million in 2020 and $8.9 million in 2025 for Option 2. More detailed cost estimates are available in the RIA included in the rulemaking docket.

F. What are the economic and employment impacts?

The proposed standards are projected to result in certain changes to power system operation as a result of the application of state emission rate goals. Overall, we project dispatch changes, changes to fossil fuel and retail electricity prices, and some additional coal retirements. Average electric power sector-delivered natural gas prices are projected to increase by roughly 9 to 12 percent in 2020 in Option 1, with negligible changes by 2030. Under Option 2, electric power sector natural gas prices are projected to increase by roughly 8 percent in 2020, on an average nationwide basis, and increase by 1 percent or less in 2025. The average delivered coal price to the power sector is projected to decrease by 16 to 17 percent in 2020 under Option 1, and decrease by roughly 14 percent under Option 2, on a nationwide average basis. Retail electricity prices are projected to increase 6 to 7 percent under Option 1 and increase by roughly 4 percent under Option 2, both in 2020 and on an average basis across the contiguous U.S. By 2030 under Option 1, electricity prices are projected to increase by about 3 percent. Under Option 1, the EPA projects 46 to 50 GW of additional coal-fired generation may be uneconomic to maintain and may be removed from operation by 2030. The EPA projects that under Option 2, 30 to 33 GW of additional coal-fired generation may be uneconomic to maintain and may be removed from operation by 2025.

It is important to note that the EPA's modeling does not necessarily account for all of the factors that may influence business decisions regarding future coal fired capacity. By 2025, the average age of the coal-fired fleet will be 49 years old and twenty percent of the fleet will be more than 60 years old. Many power companies already factor a carbon price into their long term capacity planning that would further influence business decisions to replace these aging assets with modern, and significantly cleaner generation.

The compliance modeling done to support the proposal assumes that overall electric demand will decrease significantly, as states ramp up programs that result in lower overall demand. End-use energy efficiency levels increase such that they achieve about an 11 percent reduction on overall electricity demand levels in 2030 for Option 1, and a reduction in overall electricity demand of approximately 6 percent reduction in 2025 for Option 2. In response, there are anticipated to be notable changes to costs, prices, and electricity generation in the power sector as more end-use efficiency is realized.

Changes in price or demand for electricity, natural gas, coal, can impact markets for goods and services produced by sectors that use these energy inputs in the production process or supply those sectors. Changes in cost of production may result in changes in price, changes in quantity produced, and changes in profitability of firms affected. The EPA recognizes that these guidelines provide significant flexibilities and states implementing the guidelines may choose to mitigate impacts to some markets outside the EGU sector. Similarly, demand for new generation or energy efficiency can result in shifts in production and profitability for firms that supply those goods and services, and the guidelines provide flexibility for states that may want to enhance demand for goods and services from those sectors.

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, ''our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science.'' (Executive Order 13563, 2011) Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts, we typically conduct employment analyses. During periods of sustained high unemployment, employment impacts are of particular concern and questions may arise about their existence and magnitude.

States have the responsibility and flexibility to implement policies and practices for compliance with Proposed Electric Generating Unit Greenhouse Gas Existing Source Guidelines. Quantifying the associated employment impacts is complicated by the wide range of approaches that States may use. As such, the EPA's employment analysis includes projected employment impacts associated with illustrative compliance scenarios for these guidelines for the electric power industry, coal and natural gas production, and demand-side energy efficiency activities. These projections are derived, in part, from a detailed model of the electricity production sector used for this regulatory analysis, and U.S government data on employment and labor productivity. In the electricity, coal, and natural gas sectors, the EPA estimates that these guidelines could have an employment impact of roughly 25,900 to 28,000 job-years increase in 2020 for Option 1, state to regional compliance approach, respectively. For Option 2, the state and regional compliance approach estimates are 26,700 to 29,800 job-years increase in 2020. Demand-side energy efficiency employment impacts are approximately an increase of 78,800 jobs in 2020 for Option 1 and of 57,000 jobs for Option 2. By its nature, energy efficiency reduces overall demand for electric power. The EPA recognizes as more efficiency is built into the U.S. power system over time, lower fuel requirements may lead to fewer jobs in the coal and natural gas extraction sectors, as well as in EGU construction and operation than would otherwise have been expected. The EPA also recognizes the fact that, in many cases, employment gains and losses that might be attributable to this rule would be expected to affect different sets of people. Moreover, workers who lose jobs in these sectors may find employment elsewhere just as workers employed in new jobs in these sectors may have been previously employed elsewhere. Therefore, the employment estimates reported in these sectors may include workers previously employed elsewhere. This analysis also does not capture potential economy-wide impacts due to changes in prices (of fuel, electricity, labor, etc.). For these reasons, the numbers reported here

should not be interpreted as a net national employment impact.

G. What are the benefits of the proposed goals?

Implementing the proposed standards will generate benefits by reducing emissions of CO_2 as well as criteria pollutants and their precursors, including SO_2, NO_X and directly emitted particles. SO_2 and NO_X are precursors to $PM_{2.5}$ (particles smaller than 2.5 microns), and NO_X is a precursor to ozone. The estimated benefits associated with these emission reductions are beyond those achieved by previous EPA rulemakings including the Mercury and Air Toxics Standards rule. The health and welfare benefits from reducing air pollution are considered co-benefits for these standards. For this rulemaking, we were only able to quantify the climate benefits from reduced emissions of CO_2 and the health co-benefits associated with reduced exposure to $PM_{2.5}$ and ozone. In summary, we estimate the total combined climate benefits and health co-benefits for Option 1 to be $33 billion to $54 billion in 2020 and $55 billion to $89 billion in 2030 assuming a regional compliance approach (2011 dollars at a 3-percent discount rate [model average]). If states comply using a state-specific compliance approach, these climate and health co-benefits estimates are estimated to be $35 to $57 billion in 2020 and $57 to $93 billion in 2030 (2011 dollars at a 3-percent discount rate [model average]). We also estimate the total combined climate benefits and health co-benefits for Option 2 to be $26 billion to $44 billion in 2020 and $36 billion to $59 billion in 2025 (regional compliance approach, 2011 dollars at a 3-percent discount rate [model average]). Assuming a state compliance approach, the total combined climate benefits and health co-benefits for Option 2 are estimated to be $27 billion to $45 billion in 2020 and $36 billion to $60 billion in 2025 (2011 dollars at a 3-percent discount rate [model average]). A summary of the emission reductions and monetized benefits estimated for this rule at all discount rates and additional analysis years is provided in Tables 12 through 17 of this preamble.

TABLE 12—SUMMARY OF THE MONETIZED GLOBAL CLIMATE BENEFITS FOR THE PROPOSED OPTION 1

[Billions of 2011 dollars] [a]

2020	Discount rate (statistic)	Monetized climate benefits	
		Regional compliance	State compliance
CO_2 Reductions (million metric tons)		371	383
	5 percent (average SCC)	$4.7	$4.9
	3 percent (average SCC)	$17	$18
	2.5 percent (average SCC)	$25	$26
	3 percent (95th percentile SCC)	$51	$52
2025			
CO_2 Reductions (million metric tons)		501	506
	5 percent (average SCC)	$7.5	$7.6
	3 percent (average SCC)	$25	$25
	2.5 percent (average SCC)	$37	$37
	3 percent (95th percentile SCC)	$76	$77
2030			
CO_2 Reductions (million metric tons)		545	555
	5 percent (average SCC)	$9.3	$9.5
	3 percent (average SCC)	$30	$31
	2.5 percent (average SCC)	$44	$44
	3 percent (95th percentile SCC)	$92	$94

[a] Climate benefit estimates reflect impacts from CO_2 emission changes in the analysis years presented in the table and do not account for changes in non-CO_2 GHG emissions. These estimates are based on the global social cost of carbon (SCC) estimates for the analysis years (2020, 2025, and 2030) and are rounded to two significant figures.

TABLE 13—SUMMARY OF THE MONETIZED GLOBAL CLIMATE BENEFITS FOR THE OPTION 2

[Billions of 2011 dollars] [a]

2020	Discount rate (statistic)	Monetized climate benefits	
		Regional compliance	State compliance
CO_2 Reductions (million metric tons)		283	295
	5 percent (average SCC)	$3.6	$3.8
	3 percent (average SCC)	$13	$14
	2.5 percent (average SCC)	$19	$20
	3 percent (95th percentile SCC)	$39	$40
2025			
CO_2 Reductions (million metric tons)		368	376
	5 percent (average SCC)	$5.5	$5.6
	3 percent (average SCC)	$18	$19

TABLE 13—SUMMARY OF THE MONETIZED GLOBAL CLIMATE BENEFITS FOR THE OPTION 2—Continued

[Billions of 2011 dollars] [a]

2020	Discount rate (statistic)	Monetized climate benefits	
		Regional compliance	State compliance
	2.5 percent (average SCC)	$27	$28
	3 percent (95th percentile SCC)	$56	$57

[a] Climate benefit estimates reflect impacts from CO_2 emission changes in the analysis years presented in the table and do not account for changes in non-CO_2 GHG emissions. These estimates are based on the global SCC estimates for the analysis years (2020, 2025, and 2030) and are rounded to two significant figures.

TABLE 14—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS FOR THE PROPOSED STANDARDS OPTION 1 REGIONAL COMPLIANCE APPROACH IN THE U.S.

[Billions of 2011 dollars] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Option 1 Regional Compliance Approach 2020			
$PM_{2.5}$ precursors: [b]			
SO_2	292	$12 to $26	$11 to $24
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	6	$0.75 to $1.7	$0.67 to $1.5
Directly emitted $PM_{2.5}$ (crustal)	44	$0.77 to $1.7	$0.69 to $1.6
NO_X	345	$2.2 to $5.0	$2.0 to $4.5
Ozone precursor: [c]			
NO_X (ozone season only)	146	$0.63 to $2.7	$0.63 to $2.7
Total Monetized Health Co-benefits		$16 to $37	$15 to $34
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$33 to $54	$32 to $51
Option 1 Regional Compliance Approach 2025			
$PM_{2.5}$ precursors [b]			
SO_2	395	$17 to $38	$15 to $35
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	6	$0.85 to $1.9	$0.76 to $1.7
Directly emitted $PM_{2.5}$ (crustal)	46	$0.78 to $1.8	$0.70 to $1.6
NO_X	421	$3.0 to $6.8	$2.7 to $6.1
Ozone precursor: [c]			
NO_X (ozone season only)	180	$1.0 to $4.3	$1.0 to $4.3
Total Monetized Health Co-benefits		$23 to $53	$21 to $48
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$48 to $78	$46 to $74
Option 1 Regional Compliance Approach 2030			
$PM_{2.5}$ precursors: [b]			
SO_2	424	$20 to $44	$18 to $40
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	5	$0.84 to $1.9	$0.76 to $1.7
Directly emitted $PM_{2.5}$ (crustal)	42	$0.77 to $1.7	$0.70 to $1.6
NO_X	407	$3.0 to $6.7	$2.7 to $6.1
Ozone precursor: [c]			
NO_X(ozone season only)	176	$1.1 to $4.5	$1.1 to $4.5
Total Monetized Health Co-benefits		$25 to $59	$23 to $54
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$55 to $89	$53 to $84

[a] All estimates are for the analysis years (2020, 2025, 2030) and are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2, NO_X and directly emitted $PM_{2.5}$. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), which each increase over time. For the purposes of this table, we show the benefits associated with the model average at 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. We provide combined climate and health estimates based on additional discount rates in the RIA.

TABLE 15—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE PROPOSED GUIDELINES OPTION 1 STATE COMPLIANCE APPROACH

[Billions of 2011 dollars] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Option 1 State Compliance Approach in 2020			
$PM_{2.5}$ precursors: [b]			
SO_2	335	$13 to $29	$11 to $26
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	6	$0.76 to $1.7	$0.69 to $1.6
Directly emitted $PM_{2.5}$ (crustal)	45	$0.79 to $1.8	$0.71 to $1.6
NO_X	367	$2.2 to $4.9	$2.0 to $4.4
Ozone precursor: [c]			
NO_X (ozone season only)	157	$0.64 to $2.7	$0.64 to $2.7
Total Monetized Health Co-benefits		$17 to $40	$15 to $36
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$35 to $57	$33 to $54
Option 1 State Compliance Approach in 2025			
$PM_{2.5}$ precursors: [b]			
SO_2	425	$18 to $40	$16 to $36
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	6	$0.90 to $2.0	$0.81 to $1.8
Directly emitted $PM_{2.5}$ (crustal)	49	$0.83 to $1.9	$0.75 to $1.7
NO_X	436	$2.9 to $6.5	$2.6 to $5.8
Ozone precursor: [c]			
NO_X (ozone season only)	190	$1.0 to $4.4	$1.0 to $4.4
Total Monetized Health Co-benefits		$23 to $54	$21 to $49
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$49 to $80	$46 to $75
Option 1 State Compliance Approach in 2030			
$PM_{2.5}$ precursors: [b]			
SO_2	471	$21 to $47	$19 to $43
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	6	$0.87 to $2.0	$0.78 to $1.8
Directly emitted $PM_{2.5}$ (crustal)	44	$0.80 to $1.8	$0.72 to $1.6
NO_X	428	$2.9 to $6.6	$2.6 to $6.0
Ozone precursor: [c]			
NO_X (ozone season only)	187	$1.1 to $4.6	$1.1 to $4.6
Total Monetized Health Co-benefits		$27 to $62	$24 to $57
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$57 to $93	$55 to $87

[a] All estimates are for the analysis years (2020, 2025, 2030) and are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2, NO_X and directly emitted $PM_{2.5}$. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), which each increase over time. For the purposes of this table, we show the benefits associated with the model average at 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. We provide combined climate and health estimates based on additional discount rates in the RIA.

TABLE 16—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE OPTION 2 REGIONAL COMPLIANCE APPROACH

[Billions of 2011 dollars] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Option 2 Regional Compliance Approach 2020			
$PM_{2.5}$ precursors: [b]			
SO_2	244	$9.8 to $22	$8.9 to $20
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	5	$0.61 to $1.4	$0.55 to $1.2
Directly emitted $PM_{2.5}$ (crustal)	36	$0.63 to $1.4	$0.57 to $1.3
NO_X	268	$1.7 to $3.9	$1.6 to $3.5
Ozone precursor: [c]			

TABLE 16—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR THE OPTION 2 REGIONAL COMPLIANCE APPROACH—Continued

[Billions of 2011 dollars] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
NO_X (ozone season only)	111	$0.47 to $2.0	$0.47 to $2.0
Total Monetized Health Co-benefits		$13 to $31	$12 to $28
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$26 to $44	$25 to $41
Option 2 Regional Compliance Approach in 2025			
$PM_{2.5}$ precursors: [b]			
SO_2	297	$13 to $29	$12 to $26
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon)	4	$0.64 to $1.4	$0.58 to $1.3
Directly emitted $PM_{2.5}$ (crustal)	34	$0.59 to $1.3	$0.53 to $1.2
NO_X	309	$2.2 to $5.0	$2.0 to $4.5
Ozone precursor: [c]			
NO_X (ozone season only)	129	$0.73 to $3.1	$0.73 to $3.1
Total Monetized Health Co-benefits		$17 to $40	$16 to $36
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d]		$36 to $59	$34 to $55

[a] All estimates are for the analysis years (2020, 2025) and are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2, NO_X and directly emitted $PM_{2.5}$. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), which each increase over time. For the purposes of this table, we show the benefits associated with the model average at 3% discount rate, however we emphasize the importance and value of considering the full range of SCC values. We provide combined climate and health estimates based on additional discount rates in the RIA.

TABLE 17—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR OPTION 2 STATE COMPLIANCE APPROACH

[Billions of 2011 dollars] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
Option 2 State Compliance Approach in 2020			
$PM_{2.5}$ precursors: [b]			
SO_2	267	$10 to $23	$9.1 to $21
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon).	5	$0.64 to $1.5	$0.58 to $1.3
Directly emitted $PM_{2.5}$ (crustal)	38	$0.66 to $1.5	$0.60 to $1.4
NO_X	281	$1.7 to $3.8	$1.5 to $3.4
Ozone precursor: [c]			
NO_X (ozone season only)	119	$0.48 to $2.1	$0.48 to $2.1
Total Monetized Health Co-benefits		$14 to $32	$12 to $29
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d].		$27 to $45	$26 to $42
Option 2 State Compliance Approach in 2025			
$PM_{2.5}$ precursors: [b]			
SO_2	327	$14 to $30	$12 to $27
Directly emitted $PM_{2.5}$ (Elemental Carbon and Organic Carbon).	5	$0.69 to $1.6	$0.63 to $1.4
Directly emitted $PM_{2.5}$ (crustal)	38	$0.64 to $1.4	$0.58 to $1.3
NO_X	317	$2.1 to $4.7	$1.9 to $4.2
Ozone precursor: [c]			

TABLE 17—SUMMARY OF THE MONETIZED HEALTH CO-BENEFITS IN THE U.S. FOR OPTION 2 STATE COMPLIANCE APPROACH—Continued

[Billions of 2011 dollars] [a]

Pollutant	National emission reductions (thousands of short tons)	Monetized health co-benefits (3 percent discount)	Monetized health co-benefits (7 percent discount)
NO_X (ozone season only)	136	$0.72 to $3.1	$0.72 to $3.1
Total Monetized Health Co-benefits		$18 to $41	$16 to $16
Total Monetized Health Co-benefits combined with Monetized Climate Benefits [d].		$36 to $60	$35 to $56

[a] All estimates are for the analysis years (2020, 2025) and are rounded to two significant figures, so estimates may not sum. It is important to note that the monetized co-benefits do not include reduced health effects from direct exposure to SO_2, direct exposure to NO_2, ecosystem effects or visibility impairment. Air pollution health co-benefits are estimated using regional benefit-per-ton estimates for the contiguous U.S.

[b] The monetized $PM_{2.5}$ co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors, such as SO_2, NO_X and directly emitted $PM_{2.5}$. PM co-benefits are shown as a range reflecting the use of two concentration-response functions, with the lower end of the range based on a function from Krewski et al. (2009) and the upper end based on a function from Lepeule et al. (2012). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[c] The monetized ozone co-benefits reflect the human health benefits associated with reducing exposure to ozone through reductions of NO_X during the ozone season. Ozone co-benefits are shown as a range reflecting the use of several different concentration-response functions, with the lower end of the range based on a function from Bell, et al. (2004) and the upper end based on a function from Levy, et al. (2005). Ozone co-benefits occur in the analysis year, so they are the same for all discount rates.

[d] We estimate climate benefits associated with four different values of a one ton CO_2 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), which each increase over time. For the purposes of this table, we show the benefits associated with the model average at 3% discount rate; however, we emphasize the importance and value of considering the full range of SCC values. We provide combined climate and health estimates based on additional discount rates in the RIA.

The EPA has used the social cost of carbon (SCC) estimates presented in the 2013 *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (2013 SCC TSD) to analyze CO_2 climate impacts of this rulemaking.[331] We refer to these estimates, which were developed by the U.S. government, as ''SCC estimates.'' The U.S. government first published the SCC estimates in 2010 following an interagency process that included the EPA and other executive branch entities; the process used three integrated assessment models (IAM) to develop SCC estimates and selected four global values for use in regulatory analyses. The U.S. government recently updated these estimates using new versions of each integrated assessment model and published them in 2013. The 2013 update did not revisit the 2010 modeling decisions (e.g., with regard to the discount rate, reference case socioeconomic and emission scenarios or equilibrium climate sensitivity). Rather, improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves and published in the peer-reviewed literature. The 2010 SCC Technical Support Document (2010 SCC TSD) provides a complete discussion of the methods used to develop these estimates and the 2013 SCC TSD presents and discusses the updated estimates.[332]

The EPA and other agencies have sought public comment on the SCC estimates as part of various rulemakings. In addition, OMB's Office of Information and Regulatory Affairs recently sought public comment on the approach used to develop the estimates. The comment period ended on February 26, 2014, and OMB is reviewing the comments received.

The four SCC estimates, updated in 2013, are as follows: $13, $46, $68, and $137 per metric ton of CO_2 emissions in the year 2020 (2011 dollars).[333] The first three values are based on the average SCC from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. SCCs at several discount rates are included because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the SCC from all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution (representing less likely, but potentially catastrophic, outcomes).

The 2010 SCC TSD noted a number of limitations to the SCC analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and

[331] Docket ID EPA–HQ–OAR–2013–0495, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised November 2013). Available at: *http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.*

[332] Docket ID EPA–HQ–OAR–2009–0472–114577, *Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon,* with participation by the Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Also available at: *http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf*>.

[333] The 2010 and 2013 TSDs present SCC in $2007. The estimates were adjusted to 2011$ using the GDP Implicit Price Deflator. Also available at: *http://www.gpo.gov/fdsys/pkg/ECONI-2013-02/pdf/ECONI-2013-02-Pg3.pdf.*

technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Current integrated assessment models do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature for various reasons, including the inherent difficulties in valuing non-market impacts and the fact that the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 emission reductions to inform the benefit-cost analysis. Model developers continually update the models to incorporate recent research. The new versions of the models used to estimate the values presented in this rulemaking offer some improvements in these areas identified above, although further work is warranted. Accordingly, the EPA and other parties continue to conduct research on modeling and valuation of climate impacts with the goal of improving these estimates. Additional details are provided in the SCC TSDs.

The health co-benefits estimates represent the total monetized human health benefits for populations exposed to reduced $PM_{2.5}$ and ozone resulting from emission reductions under illustrative compliance options for the proposed standards. Unlike the global SCC estimates, the air pollution health co-benefits are estimated for the contiguous U.S. only. We used a ''benefit-per-ton'' approach to estimate the benefits of this rulemaking. To create the $PM_{2.5}$ benefit-per-ton estimates, this approach uses a model to convert emissions of $PM_{2.5}$ precursors into changes in ambient $PM_{2.5}$ levels and another model to estimate the changes in human health effects associated with that change in air quality, which are then divided by the emissions in specific sectors. We derived national average benefit-per-ton estimates for the EGU sector using the approach published in Fann et al. (2012),[334] and updated those estimates to reflect the studies and population data in the 2012 PM NAAQS RIA. We further separated the national estimates into regional estimates to provide greater spatial resolution.[335] In addition, we generated regional benefit-per-ton estimates for changes in ozone exposure. The ozone estimates used the ozone information from the sector modeling for the EGU sector described in Fann et al. (2012) and the health impact assumptions used in the Ozone NAAQS RIAs.[336] [337] To calculate the co-benefits for the proposed standards, we multiplied the regional benefit-per-ton estimates for the EGU sector by the corresponding emission reductions.[338] All benefit-per-ton estimates reflect the geographic distribution of the modeled emissions, which may not exactly match the emission reductions in this rulemaking, and thus they may not reflect the local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location. More information regarding the derivation of the benefit-per-ton estimates is available in the RIA.

These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure.

It is important to note that the magnitude of the $PM_{2.5}$ and ozone co-benefits is largely driven by the concentration response functions for premature mortality and the value of a statistical life used to value reductions in premature mortality. For $PM_{2.5}$, we cite two key empirical studies, one based on the American Cancer Society cohort study [339] and the extended Six Cities cohort study.[340] We present the $PM_{2.5}$ co-benefits results as a range based on the concentration-response functions from these two epidemiology studies, but this range does not capture the full range of uncertainty inherent in the co-benefits estimates. In the RIA for this rule, which is available in the docket, we also include $PM_{2.5}$ co-benefits estimates derived from expert judgments (Roman et al., 2008) [341] as a characterization of uncertainty regarding the $PM_{2.5}$-mortality relationship. For the ozone co-benefits, we present the results as a range reflecting the use of several different concentration-response functions for mortality, with the lower end of the range based on a function from Bell et al. (2004) [342] and the upper end based on a function from Levy et al. (2005).[343] Similar to $PM_{2.5}$, the range of ozone co-benefits does not capture the full range of inherent uncertainty.

In this analysis, the EPA assumes that the health impact function for fine particles is without a threshold. This is based on the conclusions of EPA's *Integrated Science Assessment for Particulate Matter,*[344] which evaluated the substantial body of published scientific literature, reflecting thousands of epidemiology, toxicology, and clinical studies that documents the association between elevated $PM_{2.5}$

[334] Fann, N., K.R. Baker and C.M. Fulcher. 2012. ''Characterizing the $PM_{2.5}$-related health benefits of emission reductions for 17 industrial, area and mobile emission sectors across the U.S.'' *Environment International* 49 41–151.

[335] U.S. Environmental Protection Agency (U.S. EPA). 2012. *Regulatory Impact Analysis for the Final Revisions to the National Ambient Air Quality Standards for Particulate Matter.* Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. (EPA document number EPA–452/R–12–003, December). Available at: <*http://www.epa.gov/pm/2012/finalria.pdf*>.

[336] U.S. Environmental Protection Agency (U.S. EPA). 2008b. *Final Ozone NAAQS Regulatory Impact Analysis.* Research Triangle Park, NC: Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, Air Benefit and Cost Group Research. (EPA document number EPA–452/R–08–003, March). Available at: <*http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=194645*>.

[337] U.S. Environmental Protection Agency (U.S. EPA). 2010. *Section 3: Re-analysis of the Benefits of Attaining Alternative Ozone Standards to Incorporate Current Methods.* Available at <*http://www.epa.gov/ttnecas1/regdata/RIAs/s3-supplemental_analysis-updated_benefits11-5.09.pdf*>.

[338] U.S. Environmental Protection Agency. 2013. *Technical support document: Estimating the benefit per ton of reducing $PM_{2.5}$ precursors from 17 sectors.* Research Triangle Park, NC: Office of Air and Radiation, Office of Air Quality Planning and Standards, January. Available at: <*http://www.epa.gov/airquality/benmap/models/Source_Apportionment_BPT_TSD_1_31_13.pdf*>.

[339] Krewski D.; M. Jerrett; R.T. Burnett; R. Ma; E. Hughes; Y. Shi, et al. 2009. *Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality.* Health Effects Institute. (HEI Research Report number 140). Boston, MA: Health Effects Institute.

[340] Lepeule, J.; F. Laden; D. Dockery; J. Schwartz. 2012. ''Chronic Exposure to Fine Particles and Mortality: An Extended Follow-Up of the Harvard Six Cities Study from 1974 to 2009.'' *Environmental Health Perspective,* 120(7), July, pp. 965–970.

[341] Roman, H., et al. 2008. ''Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S.'' *Environmental Science & Technology,* Vol. 42, No. 7, February, pp. 2268–2274.

[342] Bell, M.L., et al. 2004. ''Ozone and Short-Term Mortality in 95 U.S. Urban Communities, 1987–2000.'' *Journal of the American Medical Association,* 292(19), pp. 2372–8.

[343] Levy, J.I., S.M. Chemerynski, and J.A. Sarnat. 2005. ''Ozone exposure and mortality: an empiric bayes metaregression analysis.'' *Epidemiology.* 16(4): p. 458–68.

[344] U.S. Environmental Protection Agency. 2009. *Integrated Science Assessment for Particulate Matter (Final Report).* Research Triangle Park, NC: National Center for Environmental Assessment, RTP Division. (EPA document number EPA–600–R–08–139F, December). Available at: <*http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546*>.

concentrations and adverse health effects, including increased premature mortality. This assessment, which was twice reviewed by the EPA's independent Science Advisory Board, concluded that the scientific literature consistently finds that a no-threshold model most adequately portrays the PM-mortality concentration-response relationship.

In general, we are more confident in the magnitude of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies.

For this analysis, policy-specific air quality data are not available,[345] and thus, we are unable to estimate the percentage of premature mortality associated with this specific rule's emission reductions at each $PM_{2.5}$ level. As a surrogate measure of mortality impacts, we provide the percentage of the population exposed above the lowest measured $PM_{2.5}$ level (LML) in each of the studies from which we obtained concentration-response functions for $PM_{2.5}$ mortality, using the estimates of $PM_{2.5}$ from the source apportionment modeling used to calculate the benefit-per-ton estimates for the EGU sector. Using the Krewski et al. (2009) study, 93 percent of the population is exposed to annual mean $PM_{2.5}$ levels at or above the LML of 5.8 micrograms per cubic meter ($\mu g/m^3$). Using the Lepeule et al. (2012) study, 67 percent of the population is exposed above the LML of 8 $\mu g/m^3$. It is important to note that baseline exposure is only one parameter in the health impact function, along with baseline incidence rates, population, and change in air quality. Therefore, caution is warranted when interpreting the LML assessment for this rule because these results are not consistent with results from rules that had air quality modeling.

Every benefit analysis examining the potential effects of a change in environmental protection requirements is limited, to some extent, by data gaps, model capabilities (such as geographic coverage) and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Despite these uncertainties, we believe the air quality co-benefit analysis for this rule provides a reasonable indication of the expected health benefits of the air pollution emission reductions for the illustrative compliance options for the proposed standards under a set of reasonable assumptions. This analysis does not include the type of detailed uncertainty assessment found in the 2012 $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS) RIA (U.S. EPA, 2012) because we lack the necessary air quality input and monitoring data to conduct a complete benefits assessment. In addition, using a benefit-per-ton approach adds another important source of uncertainty to the benefits estimates. The 2012 $PM_{2.5}$ NAAQS benefits analysis provides an indication of the sensitivity of our results to various assumptions.

We note that the monetized co-benefits estimates shown here do not include several important benefit categories, including exposure to SO_2, NO_X, and hazardous air pollutants (e.g., mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment. Although we do not have sufficient information or modeling available to provide monetized estimates for this rule, we include a qualitative assessment of these unquantified benefits in the RIA for these proposed amendments.

For more information on the benefits analysis, please refer to the RIA for this rule, which is available in the rulemaking docket.

XI. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review, and Executive Order 13563, Improving Regulation and Regulatory Review

Under Section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities. The $100 million threshold can be triggered by either costs or benefits, or a combination of them. Accordingly, the EPA submitted this action to OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011), and any changes made in response to OMB recommendations have been documented in the docket for this action.

The EPA also prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the RIA for this proposed rule. A copy of the analysis is available in the docket for this action.

Consistent with EO 12866 and EO 13563, the EPA estimated the costs and benefits for illustrative compliance approaches of implementing the proposed guidelines. This proposal sets goals to reduce CO_2 emissions from the electric power industry. Actions taken to comply with the proposed guidelines will also reduce the emissions of directly emitted $PM_{2.5}$, sulfur dioxide (SO_2) and nitrogen oxides (NO_X). The benefits associated with these PM, SO_2 and NO_X reductions are referred to as co-benefits, as these reductions are not the primary objective of this rule.

The EPA has used the social cost of carbon estimates presented in the 2013 *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (2013 SCC TSD) to analyze CO_2 climate impacts of this rulemaking. We refer to these estimates, which were developed by the U.S. government, as ''SCC estimates.'' The SCC is an estimate of the monetary value of impacts associated with a marginal change in CO_2 emissions in a given year. The four SCC estimates are associated with different discount rates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent), and each increases over time. In this summary, the EPA provides the estimate of climate benefits associated with the SCC value deemed to be central in the SCC TSD: The model average at 3% discount rate. For the regional compliance approach, the EPA estimates that in 2020 this Option 1 proposal will yield monetized climate benefits (in 2011$) of approximately $17 billion (3 percent model average). The air pollution health co-benefits in 2020 are estimated to be $16 billion to $37 billion (2011$) for a 3 percent discount rate and $15 billion to $34 billion (2011$) for a 7 percent discount rate. The annual, illustrative compliance costs estimated by IPM and inclusive of demand side energy efficiency program and participant costs and MRR costs, are approximately $5.5 billion (2011$) in 2020. The quantified net benefits (the difference between monetized benefits and costs) in 2020 are estimated to be $28 billion to $49 billion assuming a regional compliance approach (2011$) using a 3 percent discount rate (model average). This range of net benefits is estimated to be $27 billion to $50 billion assuming a state compliance approach (2011$)

[345] In addition, site-specific emission reductions will depend upon how states implement the guidelines.

using a 3 percent discount rate (model average). Table 18 shows the climate benefits, health co-benefits, cost and net benefits for Option 1 in 2020 for state and regional compliance approaches. Table 19 shows similar estimates for 2030.

For Option 1 in 2030 assuming a regional compliance approach, the EPA estimates this proposal will yield monetized climate benefits (in 2011$) of approximately $30 billion (3 percent, model average). The air pollution health co-benefits in 2030 are estimated to be $25 billion to $59 billion (2011$) for a 3 percent discount rate and $23 billion to $54 billion (2011$) for a 7 percent discount rate. The annual illustrative compliance costs estimated using IPM, inclusive of a demand-side energy efficiency program and participant costs and MRR costs, are approximately $7.3 billion (2011$) in 2030. The quantified net benefits (the difference between monetized benefits and costs) in 2030 are estimated to be $48 billion to $82 billion (2011$) using a 3 percent discount rate (model average). The EPA estimates that this proposal will yield monetized climate benefits (in 2011$) of approximately $31 billion (3 percent, model average) for Option 1 state compliance approach in 2030. The air pollution health co-benefits in 2030 are estimated to be $27 billion to $62 billion (2011$) for a 3 percent discount rate and $24 billion to $56 billion (2011$) for a 7 percent discount rate. The annual illustrative compliance costs estimated using IPM, inclusive of demand side energy efficiency program and participant costs and MRR costs, are approximately $8.8 billion (2011$) in 2030. The quantified net benefits (the difference between monetized benefits and costs) in 2030 are estimated to be $49 billion to $84 billion (2011$) using a 3 percent discount rate (model average) assuming a state compliance approach. Based upon the foregoing discussion, it remains clear that the benefits of the proposal Option 1 are substantial and far exceed the costs.

TABLE 18—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS AND NET BENEFITS FOR PROPOSED OPTION 1 IN 2020 [a]

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Option 1 Regional Compliance Approach		
Climate benefits [b]	$17.	
Air pollution health co-benefits [c]	$16 to $37	$15 to $34
Total Compliance Costs [d]	$5.5	$5.5
Net Monetized Benefits [e]	$28 to $49	$26 to $45
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.3 tons of Hg. Ecosystem Effects. Visibility impairment.	
Option 1 State Compliance Approach		
Climate benefits [b]	$18.	
Air pollution health co-benefits [c]	$17 to $40	$15 to $36
Total Compliance Costs [d]	$7.5	$7.5
Net Monetized Benefits [e]	$27 to $50	$26 to $46
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.5 tons of Hg. Ecosystem Effects. Visibility impairment.	

[a] All estimates are for 2020, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3 percent discount rate; however, we emphasize the importance and value of considering the full range of SCC values. As shown in the RIA, climate benefits are also estimated using the other three SCC estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

TABLE 19—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR PROPOSED OPTION 1 IN 2030 [a]

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Option 1 Regional Compliance Approach		
Climate benefits [b]	$30.	
Air pollution health co-benefits [c]	$25 to $59	$23 to $54
Total Compliance Costs [d]	$7.3	$7.3
Net Monetized Benefits [e]	$48 to $82	$46 to $77

TABLE 19—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR PROPOSED OPTION 1 IN 2030 [a]—Continued

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.7 tons of Hg and 580 tons of HCl. Ecosystem Effects. Visibility impairment.	
Option 1 State Compliance Approach		
Climate benefits [b]	$31.	
Air pollution health co-benefits [c]	$27 to $62	$24 to $56
Total Compliance Costs [d]	$8.8	$8.8
Net Monetized Benefits [e]	$49 to $84	$46 to $79
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 2.1 tons of Hg and 590 tons of HCl. Ecosystem Effects. Visibility impairment.	

[a] All estimates are for 2030, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3 percent discount rate; however, we emphasize the importance and value of considering the full range of SCC values. As shown in the RIA, climate benefits are also estimated using the other three SCC estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping, and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

The estimated costs and benefits for the regulatory alternative—Option 2 regional and state compliance approaches are shown in Tables 20 and 21. As these tables reflect, net benefits in 2020 are estimated to be $22 to $40 billion (3 percent discount rate) and $21 to $37 billion (7 percent discount rate) for Option 2 assuming regional compliance. These Option 2 net benefit estimates become $22 to $40 billion (3 percent discount rate) and $20 to $37 billion (7 percent discount rate) with the state compliance approach. In 2025, net benefits are estimated to be $31 billion to $54 billion (3 percent discount rate) and $29 billion to $50 billion (7 percent discount rate) assuming a regional compliance approach and $31 billion to $55 billion (3 percent discount rate) and $29 billion to $51 billion (7 percent discount rate) assuming a state compliance approach.

The EPA could not monetize important benefits of proposed Option 1 and regulatory alternative Option 2. Unquantified benefits include climate benefits from reducing emissions of non-CO_2 greenhouse gases and co-benefits from reducing exposure to SO_2, NO_X, and hazardous air pollutants (e.g., mercury and hydrogen chloride), as well as ecosystem effects and visibility impairment.

TABLE 20—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR PROPOSED OPTION 2 IN 2020 a

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Option 2 Regional Compliance Approach		
Climate benefits [b]	$13.	
Air pollution health co-benefits [c]	$13 to $31	$12 to $28
Total Compliance Costs [d]	$4.3	$4.3
Net Monetized Benefits [e]	$22 to $40	$21 to $37
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 0.9 tons of Hg. Ecosystem Effects. Visibility impairment.	

TABLE 20—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR PROPOSED OPTION 2 IN 2020 a—Continued

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Option 2 State Compliance Approach		
Climate benefits [b]	$14.	
Air pollution health co-benefits [c]	$14 to $32	$12 to $29
Total Compliance Costs [d]	$5.5	$5.5
Net Monetized Benefits [e]	$22 to $40	$20 to $37
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.2 tons of Hg. Ecosystem Effects. Visibility impairment.	

[a] All estimates are for 2020, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3 percent discount rate; however, we emphasize the importance and value of considering the full range of SCC values. As shown in the RIA, climate benefits are also estimated using the other three SCC estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

TABLE 21—SUMMARY OF THE MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS FOR PROPOSED OPTION 2 IN 2025 [a]

[Billions of 2011$]

	3% Discount rate	7% Discount rate
Option 2 Regional Compliance Approach		
Climate benefits [b]	$18.	
Air pollution health co-benefits [c]	$17 to $40	$16 to $36
Total Compliance Costs [d]	$4.5	$4.5
Net Monetized Benefits [e]	$31 to $54	$29 to $50
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.3 tons of Hg. Ecosystem Effects. Visibility impairment.	
Option 2 State Compliance Approach		
Climate benefits [b]	$19.	
Air pollution health co-benefits [c]	$18 to $41	$16 to $37
Total Compliance Costs [d]	$5.5	$5.5
Net Monetized Benefits [e]	$31 to $55	$29 to $51
Non-monetized Benefits	Direct exposure to SO_2 and NO_2. 1.7 tons of Hg. Ecosystem Effects. Visibility impairment.	

[a] All estimates are for 2025, and are rounded to two significant figures, so figures may not sum.

[b] The climate benefit estimate in this summary table reflects global impacts from CO_2 emission changes and does not account for changes in non-CO_2 GHG emissions. Also, different discount rates are applied to SCC than to the other estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. The benefit estimates in this table are based on the average SCC estimated for a 3 percent discount rate; however, we emphasize the importance and value of considering the full range of SCC values. As shown in the RIA, climate benefits are also estimated using the other three SCC estimates (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). The SCC estimates are year-specific and increase over time.

[c] The air pollution health co-benefits reflect reduced exposure to $PM_{2.5}$ and ozone associated with emission reductions of directly emitted $PM_{2.5}$, SO_2 and NO_X. The range reflects the use of concentration-response functions from different epidemiology studies. The reduction in premature fatalities each year accounts for over 90 percent of total monetized co-benefits from $PM_{2.5}$ and ozone. These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type.

[d] Total costs are approximated by the illustrative compliance costs estimated using the Integrated Planning Model for the proposed option and a discount rate of approximately 5 percent. This estimate includes monitoring, recordkeeping and reporting costs and demand side energy efficiency program and participant costs.

[e] The estimates of net benefits in this summary table are calculated using the global social cost of carbon at a 3 percent discount rate (model average). The RIA includes combined climate and health estimates based on these additional discount rates.

The analysis done in support of this proposal shows that the emission reductions, benefits, and costs for the illustrative compliance approaches for the proposed Option 1 (and regulatory alternative Option 2) are larger if states choose to comply on an individual basis, compared to the illustrative regional compliance approach. The regional approach allows for more flexibility across states, which results in slightly fewer emission reductions and

lower overall costs. Net benefits (the difference between benefits and costs) are roughly equivalent under the regional and state compliance approaches.

In evaluating the impacts of the proposed guidelines, we analyzed a number of uncertainties, for example evaluating different potential spatial approaches to state compliance (i.e., state and regional) and in the estimated benefits of reducing carbon dioxide and other air pollutants. For a further discussion of key evaluations of uncertainty in the regulatory analyses for this proposed rulemaking, see the RIA included in the docket.

B. Paperwork Reduction Act

The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document prepared by the EPA has been assigned the EPA ICR number 2503.01.

The information collection requirements are based on the recordkeeping and reporting burden associated with developing, implementing, and enforcing a state plan to limit CO_2 emissions from existing sources in the power 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 of this proposed action) is estimated to be a range of 316,217 hours at a total annual labor cost of $22,381,044, to 633,001 hours at a total annual labor cost of $44,802,243. The lower bound estimate reflects the assumption that some states already have energy efficiency and renewable energy programs in place. The higher bound estimate reflects the assumption that no states have energy efficiency and renewable energy programs in place. The total annual burden for the federal government (averaged over the first 3 years following promulgation of this proposed action) is estimated to be 53,300 hours at a total annual labor cost of $2,958,005. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

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 are listed in 40 CFR part 9 and 48 CFR chapter 15.

To comment on the agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, the EPA has established a public docket for this rule, which includes this ICR, under Docket ID Number EPA–HQ–OAR–2013–0602. Submit any comments related to the ICR to the EPA and to OMB. See the **ADDRESSES** section at the beginning of this notice for where to submit comments to the EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, Attention: Desk Office for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after June 18, 2014, a comment to OMB is best assured of having its full effect if OMB receives it by July 18, 2014. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (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 or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, small entity is defined as:

(1) A small business that is defined by the SBA's regulations at 13 CFR 121.201 (for the electric power generation industry, the small business size standard is an ultimate parent entity with less than 750 employees. The NAICS codes for the affected industry are in Table 22 below);

(2) A small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and

(3) A small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

TABLE 22—POTENTIALLY REGULATED CATEGORIES AND ENTITIES [a]

Category	NAICS Code	Examples of potentially regulated entities [a]
Industry	221112	Fossil fuel electric power generating units.
State/Local Government	221112 [b]	Fossil fuel electric power generating units owned by municipalities.

[a] Include NAICS categories for source categories that own and operate electric power generating units (includes boilers and stationary combined cycle combustion turbines).

[b] State or local government-owned and operated establishments are classified according to the activity in which they are engaged.

After considering the economic impacts of this proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities.

The proposed rule will not impose any requirements on small entities. Specifically, emission guidelines

established under CAA section 111(d) do not impose any requirements on regulated entities and, thus, will not have a significant economic impact upon a substantial number of small entities. After emission guidelines are promulgated, states establish standards on existing sources, and it is those state requirements that could potentially impact small entities. Our analysis here is consistent with the analysis of the analogous situation arising when the EPA establishes NAAQS, which do not impose any requirements on regulated entities. As here, any impact of a NAAQS on small entities would only arise when states take subsequent action to maintain and/or achieve the NAAQS through their state implementation plans. See *American Trucking Assoc.* v. *EPA,* 175 F.3d 1029, 1043–45 (D.C. Cir. 1999) (NAAQS do not have significant impacts upon small entities because NAAQS themselves impose no regulations upon small entities).

Nevertheless, the EPA is aware that there is substantial interest in the proposed rule among small entities (municipal and rural electric cooperatives). As detailed in Section III.A of this preamble, the EPA has conducted an unprecedented amount of stakeholder outreach on setting emission guidelines for existing EGUs. While formulating the provisions of the proposed rule, the EPA considered the input provided over the course of the stakeholder outreach. Section III.B of this preamble describes the key messages from stakeholders. In addition, as described in the RFA section of the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1499–1500, January 8, 2014), the EPA conducted outreach to representatives of small entities while formulating the provisions of the proposed standards. Although only new EGUs would be affected by those proposed standards, the outreach regarded planned actions for new and existing sources. We invite comments on all aspects of the proposal and its impacts, including potential impacts on small entities.

D. Unfunded Mandates Reform Act

This proposed action does not contain a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. Specifically, the emission guidelines proposed under CAA section 111(d) do not impose any direct compliance requirements on regulated entities, apart from the requirement for states to develop state plans. The burden for states to develop state plans in the 3-year period following promulgation of the rule was estimated and is listed in Section IX B., above, but this burden is estimated to be below $100 million in any one year. Thus, this proposed rule is not subject to the requirements of section 202 or section 205 of the Unfunded Mandates Reform Act (UMRA).

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

In light of the interest among governmental entities, the EPA initiated consultations with governmental entities while formulating the provisions of the proposed standards for new EGUs. Although only new EGUs would be affected by those proposed standards, the outreach regarded planned actions for new and existing sources. As described in the UMRA discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1500–1501, January 8, 2014), the EPA consulted with the following 10 national organizations representing state and local elected officials: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, 8) National Association of Towns and Townships, (9) County Executives of America, and 10) Environmental Council of States. On February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs.

While formulating the provisions of these proposed emission guidelines, the EPA also considered the input provided over the course of the extensive stakeholder outreach conducted by the EPA (see Sections III.A. and III.B. of this preamble).

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 EPA has concluded that this action may have federalism implications, because it may impose substantial direct compliance costs on state or local governments, and the federal government will not provide the funds necessary to pay those costs. As discussed in the Supporting Statement found in the docket for this rulemaking, the development of state plans will entail many hours of staff time to develop and coordinate programs for compliance with the proposed rule, as well as time to work with state legislatures as appropriate, and develop a plan submittal.

The EPA consulted with state and local officials early in the process of developing the proposed action to permit them to have meaningful and timely input into its development. As described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1501, January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGUs. This outreach regarded planned actions for new, reconstructed, modified and existing sources. The EPA invited the following 10 national organizations representing state and local elected officials to a meeting on April 12, 2011, in Washington DC: (1) National Governors Association; (2) National Conference of State Legislatures, (3) Council of State Governments, (4) National League of Cities, (5) U.S. Conference of Mayors, (6) National Association of Counties, (7) International City/County Management Association, (8) National Association of Towns and Townships, (9) County Executives of America, and (10) Environmental Council of States. These 10 organizations representing elected state and local officials have been identified by the EPA as the ''Big 10'' organizations appropriate to contact for purpose of consultation with elected officials. On February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs. In addition, extensive stakeholder outreach conducted by the EPA allowed state leaders, including governors, environmental commissioners, energy officers, public utility commissioners, and air directors, opportunities to engage with EPA officials and provide input regarding reducing carbon pollution from power plants.

A detailed Federalism Summary Impact Statement (FSIS) describing the

most pressing issues raised in pre-proposal and post-proposal comments will be forthcoming with the final rule, as required by section 6(b) of Executive Order 13132. In the spirit of Executive Order 13132, and consistent with the EPA's policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from State and local officials.

F. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It would not impose substantial direct compliance costs on tribal governments that have affected EGUs located in their area of Indian country. Tribes are not required to, but may, develop or adopt CAA programs. Tribes are not required to develop plans to implement the guidelines under CAA section 111(d) for affected EGUs. To the extent that a tribal government seeks and attains treatment in a manner similar to a state (TAS) status for that purpose and is delegated authority for air quality planning purposes, these proposed emission guidelines would require that planning requirements be met and emission management implementation plans be executed by the tribes. The EPA is aware of three coal-fired EGUs and one natural gas-fired EGU located in Indian country but is not aware of any affected EGUs that are owned or operated by tribal entities. The EPA notes that this proposal does not directly impose specific requirements on EGU sources, including those located in Indian country, such as the three coal-fired EGUs and one natural gas-fired EGU, but provides guidance to any tribe with delegated authority to address CO_2 emissions from EGU sources found subject to section 111(d) of the CAA. Thus, Executive Order 13175 does not apply to this action.

The EPA conducted outreach to tribal environmental staff and offered consultation with tribal officials in developing this action. Because the EPA is aware of tribal interest in this proposed rule, prior to the April 13, 2012 proposal (77 FR 22392–22441), the EPA offered consultation with tribal officials early in the process of developing the proposed regulation to permit them to have meaningful and timely input into its development. The EPA's consultation regarded planned actions for new and existing sources. In addition, on April 15, 2014, prior to proposal, the EPA met with Navajo Energy Development Group officials. For this proposed action for existing EGUs, a tribe that has one or more affected EGUs located in its area of Indian country [346] would have the opportunity, but not the obligation, to establish a CO_2 performance standard and a CAA section 111(d) plan for its area of Indian country.

Consultation letters were sent to 584 tribal leaders. The letters provided information regarding the EPA's development of both the NSPS and emission guidelines for fossil fuel-fired EGUs and offered consultation. No tribes have requested consultation. Tribes were invited to participate in the national informational webinar held August 27, 2013. In addition, a consultation/outreach meeting was held on September 9, 2013, with tribal representatives from some of the 584 tribes. The EPA also met with tribal environmental staff via National Tribal Air Association teleconferences on July 25, 2013, and December 19, 2013. In those teleconferences, the EPA provided background information on the GHG emission guidelines to be developed and a summary of issues being explored by the agency. Tribes have expressed varied points of view. Some tribes raised concerns about the impacts of the regulations on EGUs and the subsequent impact on jobs and revenue for their tribes. Other tribes expressed concern about the impact the regulations would have on the cost of water to their communities as a result of increased costs to the EGU that provide energy to transport the water to the tribes. Other tribes raised concerns about the impacts of climate change on their communities, resources, life ways and hunting and treaty rights. The tribes were also interested in the scope of the guidelines being considered by the agency (e.g., over what time period, relationship to state and multi-state plans) and how tribes will participate in these planning activities. In addition, the EPA held a series of listening sessions prior to development of this proposed action. In 2013, tribes participated in a session with the state agencies, as well as a separate session with tribes.

During the public comment period for this proposal, the EPA will hold meetings with tribal environmental staff to inform them of the content of this proposal, as well as offer further consultation with tribal elected officials where it is appropriate. We specifically solicit comment from tribal officials on this proposed rule.

[346] The EPA is aware of at least four affected EGUs located in Indian country: Two on Navajo lands, the Navajo Generating Station and the Four Corners Generating Station; one on Ute lands, the Bonanza Generating Station; and one on Fort Mojave lands, the South Point Energy Center. The affected EGUs at the first three plants are coal-fired EGUs. The fourth affected EGU is an NGCC facility.

G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to EO 13045 because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the CO_2 emission reductions resulting from implementation of the proposed guidelines, as well as substantial ozone and $PM_{2.5}$ emission reductions as a co-benefit, would further improve children's health.

H. Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355; May 22, 2001) requires the EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, OMB, for actions identified as ''significant energy actions.'' This action, which is a significant regulatory action under EO 12866, is likely to have a significant effect on the supply, distribution, or use of energy. We have prepared a Statement of Energy Effects for this action as follows. We estimate a 4 to 7 percent increase in retail electricity prices, on average, across the contiguous U.S. in 2020, and a 16 to 22 percent reduction in coal-fired electricity generation as a result of this rule. The EPA projects that electric power sector delivered natural gas prices will increase by about 8 to 12 percent in 2020. For more information on the estimated energy effects, please refer to the economic impact analysis for this proposal. The analysis is available in the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs the EPA to use Voluntary Census Standards (VCS) in its regulatory and procurement activities unless to do so would be inconsistent with applicable law or

otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs the EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable VCS. This proposed rulemaking does not involve technical standards.

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 action.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low-income populations in the U.S.

Section II.A of this preamble summarizes the public health and welfare impacts from GHG emissions that were detailed in the 2009 Endangerment Finding under CAA section 202(a)(1).[347] As part of the Endangerment Finding, the Administrator considered climate change risks to minority or low-income populations, finding that certain parts of the population may be especially vulnerable based on their circumstances. These include the poor, the elderly, the very young, those already in poor health, the disabled, those living alone, and/or indigenous populations dependent on one or a few resources. The Administrator placed weight on the fact that certain groups, including children, the elderly, and the poor, are most vulnerable to climate-related health effects.

Strong scientific evidence that the potential impacts of climate change raise environmental justice issues is found in the major assessment reports by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) of the National Academies, summarized in the record for the Endangerment Finding. Their conclusions include that poor communities can be especially vulnerable to climate change impacts because they tend to have more limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies. In addition, Native American tribal communities possess unique vulnerabilities to climate change, particularly those on established reservations that are restricted to reservation boundaries and therefore have limited relocation options. Tribal communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. Southwest native cultures are especially vulnerable to water quality and availability impacts. Native Alaskan communities are likely to experience disruptive impacts, including shifts in the range or abundance of wild species crucial to their livelihoods and well-being. The most recent assessments continue to strengthen scientific understanding of climate change risks to minority and low-income populations.

This proposed rule would limit GHG emissions by establishing CO_2 emission guidelines for existing fossil fuel-fired EGUs. In addition to reducing CO_2 emissions, implementing the proposed rule would reduce other emissions from EGUs that become dispatched less frequently due to their relatively low energy efficiency. These emission reductions will include SO_2 and NOx, which form ambient $PM_{2.5}$ and ozone in the atmosphere, and hazardous air pollutants (HAP), such as mercury and hydrochloric acid. In the final rule revising the annual $PM_{2.5}$ NAAQS,[348] the EPA identified persons with lower socioeconomic status as an at-risk population for experiencing adverse health effects related to PM exposures. Persons with lower socioeconomic status have been generally found to have a higher prevalence of pre-existing diseases, limited access to medical treatment, and increased nutritional deficiencies, which can increase this population's risk to PM-related and ozone-related effects.[349] Therefore, in areas where this rulemaking reduces exposure to $PM_{2.5}$, ozone, and methylmercury, persons with low socioeconomic status would also benefit. The RIA for this rulemaking, included in the docket for this rulemaking, provides additional information regarding the health and ecosystem effects associated with these emission reductions.

While there will be many locations with improved air quality for $PM_{2.5}$, ozone, and HAP, there may also be EGUs whose emissions of one or more of these pollutants or their precursors increase as a result of the proposed emission guidelines for existing fossil fuel-fired EGUs. This may occur at EGUs that become dispatched more intensively than in the past because they become more energy efficient. The EPA has considered the potential for such increases and the environmental justice implications of such increases.

As we noted in the NSR discussion in this preamble, as part of a state's CAA section 111(d) plan, the state may require an affected EGU to undertake a physical or operational changes to improve the unit's efficiency that result in an increase in the unit's dispatch and an increase in the unit's annual emissions of GHGs and/or other regulated pollutants. A state can take steps to avoid increased utilization of particular EGUs and thus avoid any significant increases in emissions including emissions of other regulated pollutants whose environmental effects would be more localized around the affected EGU. To the extent that states take this path, there would be no new environmental justice concerns in the areas near such EGUs. For any EGUs that make modifications that do trigger NSR permitting, the applicable local, state, or federal permitting program will ensure that there are no new NAAQS violations and that no existing NAAQS violations are made worse. For those EGUs in a permitting situation for which the EPA is the permit reviewing authority, the EPA will consider environmental justice issues as required by Executive Order 12898.

In addition to some EGUs possibly being required by a state to make modifications for increased energy efficiency, another effect of the proposed CO_2 emission guidelines for existing fossil fuel-fired EGUs would be

[347] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,'' 74 FR 66,496 (Dec. 15, 2009) (''Endangerment Finding'').

[348] ''National Ambient Air Quality Standards for Particulate Matter, Final Rule,'' 78 FR 3086 (Jan. 15, 2013).

[349] U.S. Environmental Protection Agency (U.S. EPA). 2009. *Integrated Science Assessment for Particulate Matter (Final Report).* EPA–600–R–08–139F. National Center for Environmental Assessment—RTP Division. December. Available on the Internet at <*http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546*>.

increased utilization of other, unmodified EGUs with relatively low GHG emissions per unit of electrical output, in particular high efficiency gas-fired EGUs. Because such EGUs would not have been modified physically nor changed their method of operation, they would not be subject to review in the NSR permitting program. Such plants would have more hours in the year in which they operate and emit pollutants, including pollutants whose environmental effects if any would be localized rather than global as is the case with GHG emissions. Changes in utilization already occur now as demands for and sources of electrical energy evolve, but the proposed CO_2 emission guidelines for existing fossil fuel-fired EGUs can be expected to cause more such changes. Because gas-fired EGUs emit essentially no mercury, increased utilization would not increase methylmercury concentrations in their vicinities. Increased utilization generally would not cause higher peak concentrations of $PM_{2.5}$, NOx, or ozone around such EGUs than is already occurring because peak hourly or daily emissions generally would not change, but increased utilization may make periods of relatively high concentrations more frequent. It should be noted that the gas-fired sources that are likely to become dispatched more frequently than at present have very low emissions of primary particulate matter, SO_2 and HAP per unit of electrical output, such that local (or regional) air quality for these pollutants is likely to be affected very little. For natural gas-fired EGUS, the EPA found that regulation of HAP emissions ''is not appropriate or necessary because the impacts due to HAP emissions from such units are negligible based on the results of the study documented in the utility RTC.'' [350] In studies done by DOE/NETL comparing cost and performance of coal- and NG-fired generation, they assumed SO_2, PM (and Hg) emissions to be ''negligible.'' Their studies predict NOx emissions from a NGCC unit to be approximately 10 times lower than a subcritical or supercritical coal-fired boiler. Many are also very well controlled for emission of NOx through the application of after combustion controls such as selective catalytic reduction, although not all gas-fired sources are so equipped. Depending on the specificity of the state CAA section 111(d) plan, the state may be able to predict which EGUs and communities may be in this type of situation and to address any concerns about localized NO_2 concentrations in the design of the CAA section 111(d) program, or separately from the CAA section 111(d) program but before its implementation. In any case, existing tracking systems will allow states and the EPA to be aware of the EGUs whose utilization has increased most significantly, and thus to be able to prioritize our efforts to assess whether air quality has changed in the communities in the vicinity of such EGUs. There are multiple mechanisms in the CAA to address situations in which air quality has degraded significantly. In conclusion, this proposed rule would result in regional and national pollutant reductions; however, there likely would also be some locations with more times during the year of relatively higher concentrations of pollutants with potential for effects on localized communities than would be experienced in the absence of the proposed rule. The EPA cannot exactly predict how emissions from specific EGUs would change as an outcome of the proposed rule due to the state-led implementation. Therefore, the EPA has concluded that it is not practicable to determine whether there would be disproportionately high and adverse human health or environmental effects on minority, low income, or indigenous populations from this proposed rule.

In order to provide opportunities for meaningful involvement early on in the rule making process, the EPA has hosted webinars and conference calls on August 27, 2013, and September 9, 2013, on the proposed rule specifically for environmental justice communities and has taken all comments and suggestions into consideration in the design of the emission guidelines.

The public is invited to submit comments or identify peer-reviewed studies and data that assess effects of exposure to the pollutants addressed by this proposal.

XII. Statutory Authority

The statutory authority for this action is provided by sections 111, 301, 302, and 307(d)(1)(V) of the CAA, as amended (42 U.S.C. 7411, 7601, 7602, 7607(d)(1)(V)). This action is also subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: June 2, 2014.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 60 of the Code of the Federal Regulations is proposed to be amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for Part 60 continues to read as follows:

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

■ 2. Section 60.27 is amended by revising paragraph (b) to read as follows:

§ 60.27 Actions by the Administrator.

* * * * *

(b) After receipt of a plan or plan revision, the Administrator will propose the plan or revision for approval or disapproval. The Administrator will, within four months after the date required for submission of a plan or plan revision, approve or disapprove such plan or revision or each portion thereof, except as provided in § 60.5715.

* * * * *

■ 3. Add subpart UUUU to read as follows:

Subpart UUUU: Emission Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units

Sec.

Introduction

60.5700 What is the purpose of this subpart?
60.5705 What pollutants are regulated by this subpart?
60.5710 Am I affected by this subpart?
60.5715 What is the review and approval process for my state plan?
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60.5725 In lieu of a state plan submittal, are there other acceptable option(s) for a state to meet its section 111(d) obligations?
60.5730 Is there an approval process for a negative declaration letter?
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State Plan

60.5740 What must I include in my state plan?
60.5745 Can I work with other states to develop a multi-state plan?
60.5750 Can I include existing requirements, programs, and measures in my state plan?
60.5755 What are the timing requirements for submitting my state plan?
60.5760 What must I include in an initial submittal in lieu of a complete state plan?

[350] 65 FR 79831.

60.5765 What are the state rate-based CO_2 emission performance goals?
60.5770 What is the procedure for converting my state rate-based CO_2 emission performance goal to a mass-based CO_2 emissions performance goal?
60.5775 What schedules, performance periods, and compliance periods must I include in my state plan?
60.5780 What emission standards and enforcing measures must I include in my plan?
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Applicability of State Plans to Affected EGUs

60.5790 Does this subpart directly affect EGU owners and operators in my state?
60.5795 What affected EGUs must I address in my state plan?
60.5800 What affected EGUs are exempt from my state plan?
60.5805 What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my state plan for affected EGUs?

Recordkeeping and Reporting Requirements

60.5810 What are my state recordkeeping requirements?
60.5815 What are my state reporting requirements?

Definitions

60.5820 What definitions apply to this subpart?
Table 1 to Subpart UUUU of Part 60—State Rate-based CO_2 Emission Performance Goals (Pounds of CO_2 Per Net MWh)

Introduction

§ 60.5700 What is the purpose of this subpart?

This subpart establishes emission guidelines and approval criteria for state plans that establish emission standards limiting the control of greenhouse gas emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine. An affected steam generating unit, IGCC, or stationary combustion turbine shall, for the purposes of this subpart, be referred to as an affected EGU. These emission guidelines are developed in accordance with sections 111(d) of the Clean Air Act and subpart B of this part. To the extent any requirement of this subpart is inconsistent with the requirements of subparts A or B of this part, the requirements of this subpart will apply.

§ 60.5705 What pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are greenhouse gases.

(b) The greenhouse gas regulated by this subpart is carbon dioxide (CO_2).

§ 60.5710 Am I affected by this subpart?

If you are the Administrator of an air quality program in a state with one or more affected EGUs that commenced construction on or before January 8, 2014, you must submit a state plan to the U.S. Environmental Protection Agency (EPA) that implements the emission guidelines contained in this subpart. You must submit a negative declaration letter in place of the state plan if there are no affected EGUs for which construction commenced on or before January 8, 2014 in your state.

§ 60.5715 What is the review and approval process for my state plan?

The EPA will review your state plan according to § 60.27 except that under § 60.27(b) the Administrator will have twelve months after the date required for submission of a plan or plan revision to approve or disapprove such plan or revision or each portion thereof. If you submit a request for extension under § 60.5760(a) in lieu of a complete state plan the EPA will follow the procedure in § 60.5760(b).

§ 60.5720 What if I do not submit a plan or my plan is not approvable?

If you do not submit an approvable state plan the EPA will develop a Federal plan for your state according to § 60.27 to implement the emission guidelines contained in this subpart. Owners and operators of affected entities not covered by an approved state plan must comply with a Federal plan implemented by the EPA for the state. The Federal plan is an interim action and will be automatically withdrawn when your state plan is approved.

§ 60.5725 In lieu of a state plan submittal, are there other acceptable option(s) for a state to meet its section 111(d) obligations?

A state may meet its CAA section 111(d) obligations only by submitting a complete state plan or a negative declaration letter (if applicable).

§ 60.5730 Is there an approval process for a negative declaration letter?

No. The EPA has no formal review process for negative declaration letters. Once your negative declaration letter has been received, the EPA will place a copy in the public docket and publish a notice in the **Federal Register**. If, at a later date, an affected EGU for which construction commenced on or before January 8, 2014 is found in your state, a Federal plan implementing the emission guidelines contained in this subpart would automatically apply to that affected EGU until your state plan is approved.

§ 60.5735 What authorities will not be delegated to state, local, or tribal agencies?

The authorities that will not be delegated to State, local, or tribal agencies are specified in paragraph (a) of this section.

(a) Approval of alternatives, not already approved by this subpart, to the emissions performance goals in Table 1 to this subpart established under § 60.5755.

(b) [Reserved]

State Plan

§ 60.5740 What must I include in my state plan?

(a) You must include the elements described in paragraphs (a)(1) through (11) of this section in your state plan.

(1) Identification of affected entities, including an inventory of CO_2 emissions from affected EGUs during the most recent calendar year prior to the submission of the plan for which data is available.

(2) A description of plan approach and the geographic scope of a plan (state or multi-state), including, if relevant, identification of multi-state plan participants and geographic boundaries related to plan elements.

(3) Identification of the state emission performance level for affected entities that will be achieved through implementation of the plan.

(i) The plan must specify the average emissions performance that the plan will achieve for the following periods:

(A) The 10 year interim plan performance period of 2020 through 2029.

(B) The single projection year of 2030.

(ii) The identified emission performance level for each plan performance period in paragraph (a)(3)(i) of this section must be equivalent to or better than the levels of the rate-based CO_2 emission performance goals in Table 1 of this Subpart for affected entities in your state. The emission performance levels may be in either a rate-based form or a mass based form which is calculated according to § 60.5770. The CO_2 emission performance level specified must include either of the following as applicable:

(A) For a rate-based CO_2 emission performance level, the identified level must represent the CO_2 emissions rate, in pounds of CO_2 per MWh of net energy output that will be achieved by affected entities.

(B) For a mass-based CO_2 emission performance level, the identified level of performance must represent the total tons of CO_2 that will be emitted by affected entities during each plan performance period.

(iii) For the interim plan performance period you must identify the emission performance levels anticipated under the plan during each year 2020 through 2029.

(4) A demonstration that the plan is projected to achieve each of the state's emission performance levels for affected entities according to paragraph (a)(3) of this section.

(5) Identification of emission standards for each affected entity, compliance periods for each emission standard, and demonstration that the emission standards are, when taken together, sufficiently protective to meet the state emissions performance level.

(6) A demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to an affected entity.

(7) If your state plan does not require achievement of the full level of required emission performance, and the identified interim increments of performance in paragraph (a)(3)(iii) of this section, through emission limits on EGUs, the plan must specify the following:

(i) Program implementation milestones (e.g., start of an end-use energy efficiency program, retirement of an affected EGU, or increase in portfolio requirements under a renewable portfolio standard) and milestone dates that are appropriate to the requirements, programs, and measures included in the plan.

(ii) Corrective measures that will be implemented in the event that the comparison required by § 60.5815(b) of projected versus actual emissions performance of affected entities shows that actual emissions performance is greater than 10 percent in excess to projected plan performance for the period described in § 60.5775(c)(1), and a process and schedule for implementing such corrective measures.

(8) Identification of applicable monitoring, reporting, and recordkeeping requirements for each affected entity. If applicable, these requirements must be consistent with the requirements specified in § 60.5810.

(9) Description of the process, contents, and schedule for annual state reporting to the EPA about plan implementation and progress including information required under § 60.5815.

(10) Certification that the hearing on the state plan was held, a list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission.

(11) Supporting material including:

(i) Materials demonstrating the state's legal authority to carry out each component of its plan, including emissions standards;

(ii) Materials supporting the projected emissions performance level that will be achieved by affected entities under the plan, according to paragraph (a)(4) of this section;

(iii) Materials supporting the projected mass-based emission performance goal, calculated pursuant to § 60.5770, if applicable; and

(iv) Materials necessary to support evaluation of the plan by the EPA.

(b) You must follow the requirements of subpart B of this part (Adoption and Submittal of state plans for Designated Facilities) and demonstrate that they were met in your state plan.

§ 60.5745 Can I work with other states to develop a multi-state plan?

A multi-state plan may be submitted, provided it is signed by authorized officials for each of the states participating in the multi-state plan. In this instance, the joint submittal will have the same legal effect as an individual submittal for each participating state. A multi-state plan will include all the required elements for a single-state plan specified in § 60.5740(a). A multi-state plan, if submitted by a state, must:

(a) Demonstrate CO_2 emission performance jointly for all affected entities in all states participating in the multi-state plan, as follows:

(1) For states demonstrating performance based on the CO_2 emission rate, the level of performance identified in the multi-state plan pursuant to § 60.5740(a)(3) will be a weighted (by net energy output) average lb CO_2/MWh emission rate to be achieved by all affected EGUs in the multi-state area during the plan performance period; or

(2) For states demonstrating performance based on mass CO_2 emissions, the level of performance identified in the multi-state plan pursuant to 60.5740(a)(3) will be total CO_2 emissions by all affected EGUs in the multi-state area during the plan performance period.

(b) Assign among states, according to a formula in the multi-state plan, avoided CO_2 emissions resulting from emission standards contained in the plan, from affected entities in states participating in the multi-state plan.

§ 60.5750 Can I include existing requirements, programs, and measures in my state plan?

(a) Yes, you may include existing requirements, programs and measures in your plan according to paragraphs (b) through (d) of this section.

(b) Existing state programs, requirements, and measures, may qualify for use in demonstrating that a state plan achieves the required level of emission performance specified in a plan, according to § 60.5740(a)(3).

(c) Existing state programs, requirements, and measures, may qualify for use in projecting that a state plan will achieve the required level of emission performance specified in a plan, according to § 60.5740(a)(4).

(d) Emission impacts of existing programs, requirements, and measures that occur during a plan performance period may be recognized in meeting or projecting CO_2 emission performance by affected EGUs according to § 60.5740(a)(3) and (4), as long as they meet the following requirements:

(1) Actions taken pursuant to an existing state program, requirement, or measure, such as compliance with a regulatory obligation or initiation of an action related to a program or measure, must occur after June 18, 2014; and

(2) The existing state program, requirement, or measure, and any related actions taken pursuant to such program, requirement, or measure, meet the applicable requirements pursuant to § 60.5740(a) and § 60.5780.

§ 60.5755 What are the timing requirements for submitting my state plan?

(a) You must submit your state plan with the information in § 60.5740 by June 30, 2016 unless you are submitting a request for extension according to paragraphs (b) or (c) of this section.

(b) For a state seeking a one year extension for a complete plan submittal you must include the information in § 60.5760(a) in a submittal by June 30, 2016 to receive an extension to submit your complete state plan by June 30, 2017.

(c) For states in a multi-state plan seeking a two year extension for a complete plan submittal you must include the information in § 60.5760(a) in a submittal by June 30, 2016 to receive an extension to submit your complete multi-state plan by June 30, 2018.

§ 60.5760 What must I include in an initial submittal in lieu of a complete state plan?

(a) You must include the following required elements in an initial submittal in lieu of a complete state plan:

(1) A description of the plan approach and progress made to date in developing each of the plan elements in § 60.5740;

(2) An initial projection of the level of emission performance that will be achieved under the complete plan;

(3) A commitment by the state to maintain existing state programs and

measures that limit or avoid CO_2 emissions from affected entities (e.g., renewable energy standards, unit-specific limits on operation or fuel utilization), which must at a minimum apply during the interim period prior to state submission and EPA approval of a complete plan, and must continue to apply in lieu of a complete plan if one is ultimately not submitted and approved;

(4) Justification of why additional time is needed to submit a complete plan;

(5) A comprehensive roadmap for completing the plan, including process, analytical methods and schedule (including milestones) specifying when all necessary plan components will be complete (e.g., projection of emission performance; implementing legislation, regulations and agreements; necessary approvals);

(6) Identification of existing and future programs, requirements, and measures the state intends to include in the plan;

(7) If a multi-state plan is being developed, an executed agreement(s) with other states (e.g., MOU) participating in the development of the multistate plan; and

(8) A commitment to submit a complete plan by June 30, 2017, for a single-state plan, or June 30, 2018, for a multi-state plan, and actions the state will take to show progress in addressing incomplete plan components prior to submittal of the complete plan.

(9) A description of all steps the state has already taken in furtherance of actions needed to finalize a complete plan.

(10) Evidence of an opportunity for public comment and a response to any significant comments received on issues relating to the approvability of the initial plan.

(b) You must submit either a complete state plan or an initial submittal by June 30, 2016. Where an initial submittal is submitted in lieu of a complete state plan the due date of a complete state plan will be June 30, 2017, for a single-state plan, or June 30, 2018, for a multi-state plan unless a state is notified within 60 days of the EPA receiving the initial submittal in paragraph (a) of this section that the EPA finds the initial submittal does not meet the requirements listed in paragraph (a) of this section.

§ 60.5765 What are the state rate-based CO_2 emissions performance goals?

(a) The annual average state rate-based CO_2 emission performance goals for the interim performance periods of 2020 through 2029, and the final 2030 and thereafter period are respectively listed in Table 1 of this Subpart. The state rate-based CO_2 emission performance goal may be converted to a mass-based emission performance goal according to § 60.5770.

(b)[Reserved]

§ 60.5770 What is the procedure for converting my state rate-based CO_2 emission performance goal to a mass-based CO_2 emissions performance goal?

(a) If the plan adopts a mass-based goal according to § 60.5740(a)(3), the plan must identify the mass-based goal, in tons of CO_2 emitted by affected EGUs over the plan performance period, and include a description of the analytic process, tools, methods, and assumptions used to convert from the rate-based goal for the state identified in Table 1 of this Subpart to an equivalent mass-based goal. The conversion process must include following requirements:

(1) The process, tools, methods, and assumptions used in the conversion of the rate-based goal must be included in your state plan according to § 60.5740(a)(11).

(2) The material supporting the conversion of the rate-based goal, including results, data, and descriptions, must be include in a state plan according to § 60.5740(a)(11).

(3) The conversion must represent the tons of CO_2 emissions that are projected to be emitted by affected EGUs, in the absence of emission standards contained in the plan, if the affected EGUs were to perform at an average lb CO_2/MWh rate equal to the rate-based goal for the state identified in Table 1 of this Subpart.

(b) [Reserved]

§ 60.5775 What schedules, performance periods, and compliance periods must I include in my state plan?

(a) Your state plan must include a schedule of compliance for each affected entity regulated under the plan.

(b) Your state plan must include compliance periods, as defined in section § 60.5820, for each affected entity regulated under the plan.

(c) For the interim performance period of 2020–2029 your state must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Your state plan must include increments of emissions performance (either rate based or mass based with respect to the interim level of performance set in the state plan) within the interim performance period for every 2-rolling calendar years starting January 1, 2020 and ending in 2028 (i.e. 2020–2021, 2021–2022, 2022–2023, etc.), unless other periods that ensure regular progress in the interim period are approved by the Administrator.

(2) At the end of 2029 your state must meet the interim emissions performance level specified in § 60.5740(a)(3) as averaged over the plan performance period 2020–2029.

(d) During the final performance period, 2030 and thereafter, your state must meet the final emission performance level specified in § 60.5740(a)(3) on a 3-calendar year rolling average starting January 1, 2030 (i.e., 2030–2032, 2031–2033, 2032–2034, etc.).

(e) You must include the provisions of your state plan which demonstrate progress and compliance with the requirements in this § 60.5775 and § 60.5740 in your state's annual report required in § 60.5815.

§ 60.5780 What emission standards and enforcing measures must I include in my plan?

(a) Your state plan shall include emission standard(s) that are quantifiable, verifiable, non-duplicative, permanent, and enforceable with respect to each affected entity. The plan shall include the methods by which each emission standard meets each of the following requirements in paragraphs (b) through (f) of this section.

(b) An emission standard is quantifiable with respect to an affected entity if it can be reliably measured, in a manner that can be replicated.

(c) An emission standard is verifiable with respect to an affected entity if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with the emission standard.

(d) An emission standard is non-duplicative with respect to an affected entity if it is not already incorporated as an emission standard in another state plan unless incorporated in multi-state plan.

(e) An emission standard is permanent with respect to an affected entity if the emission standard must be met for each compliance period, or unless it is replaced by another emission standard in an approved plan revision, or the state demonstrates in an approved plan revision that the emission reductions from the emission standard are no longer necessary for the state to meet its state level of performance.

(f) An emission standard is enforceable against an affected entity if:

(1) A technically accurate limitation or requirement and the time period for

the limitation or requirement is specified;

(2) Compliance requirements are clearly defined;

(3) The affected entities responsible for compliance and liable for violations can be identified;

(4) Each compliance activity or measure is enforceable as a practical matter; and

(5) The Administrator and the state maintain the ability to enforce violations and secure appropriate corrective actions pursuant to sections 113(a) through (h) of the Act.

§ 60.5785 What is the procedure for revising my state plan?

State plans can only be revised with approval by the Administrator. If one (or more) of the elements of the state plan set in § 60.5740 require revision with respect to reaching the emission performance goal set in § 60.5765 a request may be submitted to the Administrator indicating the proposed corrections to the state plan to ensure the emission performance goal is met.

Applicability of State Plans to Affected EGUs

§ 60.5790 Does this subpart directly affect EGU owners and operators in my state?

(a) This subpart does not directly affect EGU owners and operators in your state. However, EGU owners and operators must comply with the state plan that a state develops to implement the emission guidelines contained in this subpart.

(b) If a state does not submit an approvable plan or initial submittal to implement and enforce the emission guidelines contained in this subpart by June 30, 2016, the EPA will implement and enforce a Federal plan, as provided in § 60.5740, to ensure that each affected EGU within the state that commenced construction on or before January 8, 2014 reaches compliance with all the provisions of this subpart.

§ 60.5795 What affected EGUs must I address in my state plan?

(a) The EGUs that must be addressed by your state plan are any affected steam generating unit, IGCC, or stationary combustion turbine that commences construction on or before January 8, 2014.

(b) An affected EGU is a steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine that meets the relevant applicability conditions specified in paragraph (b)(1) or (2) of this section.

(1) A steam generating unit or IGCC that has a base load rating greater than 73 MW (250 MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel) and was constructed for the purpose of supplying one-third or more of its potential electric output and more than 219,000 MWh net-electric output to a utility distribution system on an annual basis.

(2) A stationary combustion turbine that has a base load rating greater than 73 MW (250 MMBtu/h), was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a 3-year rolling average basis, combusts fossil fuel for more than 10.0 percent of the heat input during a 3-year rolling average basis and combusts over 90% natural gas on a heat input basis on a 3-year rolling average basis.

§ 60.5800 What affected EGUs are exempt from my state plan?

Affected EGUs that are exempt from your state plan include: those that are subject to subpart TTTT as a result of commencing construction or reconstruction after the subpart TTTT applicability date; and those subject to subpart TTTT as a result of commencing modification or reconstruction prior becoming subject to an applicable state plan.

§ 60.5805 What applicable monitoring, recordkeeping, and reporting requirements do I need to include in my state plan for affected EGUs?

(a) A state plan must include monitoring that is no less stringent that what is described in (a)(1) through (6) of this section.

(1) If an affected EGU is required to meet a rate based emission standard they must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter.

(2) An affected EGU must measure the hourly CO_2 mass emissions from each affected unit using the procedures in paragraphs (a)(2)(i) through (v) of this section, except as provided in paragraph (a)(3) of this section.

(i) An affected EGU must install, certify, operate, maintain, and calibrate a CO_2 continuous emissions monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected EGU exhaust gases emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. If an affected EGU measures CO_2 concentration on a dry basis, they must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter.

(ii) For each monitoring system an affected EGU uses to determine the CO_2 mass emissions, they must meet the applicable certification and quality assurance procedures in § 75.20 of this chapter and Appendices B and D to part 75 of this chapter.

(iii) An affected EGU must use a laser device to measure the dimensions of each exhaust gas stack or duct at the flow monitor and the reference method sampling locations prior to the initial setup (characterization) of the flow monitor. For circular stacks, an affected EGU must measure the diameter at three or more distinct locations and average the results. For rectangular stacks or ducts, an affected EGU must measure each dimension (i.e., depth and width) at three or more distinct locations and average the results. If the flow rate monitor or reference method sampling site is relocated, an affected EGU must repeat these measurements at the new location.

(iv) An affected EGU must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions from the affected facility; an affected EGU must not apply the bias adjustment factors described in section 7.6.5 of Appendix A to part 75 of this chapter to the exhaust gas flow rate data.

(v) If an affected EGU chooses to use Method 2 in Appendix A–1 to this part to perform the required relative accuracy test audits (RATAs) of the part 75 flow rate monitoring system, they must use a calibrated Type-S pitot tube or pitot tube assembly. An affected EGU must not use the default Type-S pitot tube coefficient.

(3) If an affected EGU exclusively combusts liquid fuel and/or gaseous fuel as an alternative to complying with paragraph (b) of this section, they may determine the hourly CO_2 mass emissions by using Equation G–4 in Appendix G to part 75 of this chapter according to the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) An affected EGU must implement the applicable procedures in appendix D to part 75 of this chapter to determine hourly unit heat input rates (MMBtu/h), based on hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of each fuel combusted.

(ii) An affected EGU may determine site-specific carbon-based F-factors (F_c) using Equation F–7b in section 3.3.6 of appendix F to part 75 of this chapter, and may use these F_c values in the

emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(4) An affected EGU must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record on an hourly basis net electric output. Measurements must be performed using 0.2 accuracy class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Further, an affected EGU that is a combined heat and power facility must install, calibrate, maintain and operate equipment to continuously measure and record on an hourly basis useful thermal output and, if applicable, mechanical output, which are used with net electric output to determine net energy output.

(5) In accordance with § 60.13(g), if two or more affected EGUs that implement the continuous emissions monitoring provisions in paragraph (a)(2) of this section share a common exhaust gas stack and are subject to the same emissions standard, they may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If an affected EGU chooses this option, the hourly net electric output for the common stack must be the sum of the hourly net electric output of the individual affected facility and you must express the operating time as ''stack operating hours'' (as defined in § 72.2 of this chapter).

(6) In accordance with § 60.13(g), if the exhaust gases from an affected EGU that implements the continuous emissions monitoring provisions in paragraph (a)(2) of this section are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you elect to monitor in the ducts), they must monitor the hourly CO_2 mass emissions and the ''stack operating time'' (as defined in § 72.2 of this chapter) at each stack or duct separately. In this case, an affected EGU must determine compliance with an applicable emissions standard by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the net energy output for the affected EGU.

(b) An affected EGU must maintain records for at least 10 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(1) An affected EGU must maintain each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 60.7. An affected EGU may maintain the records off site and electronically for the remaining year(s).

(c) An affected EGU must include in a report required by the state plan covering each compliance period all hourly CO_2 emissions and all hourly net electric output and all hourly net energy output measurements for a CHP facility calculated from data monitored according to paragraph (a) of this section.

Recordkeeping and Reporting Requirements

§ 60.5810 What are my state recordkeeping requirements?

(a) States must keep records of all plan components, plan requirements, supporting documentation, and the status of meeting the plan requirements defined in the state plan on an annual basis during the interim plan performance period from 2020–2029. After 2029 states must keep records of all information that is used to support any continued effort to meet the final emissions performance goal.

(b) States must keep records of all data submitted by each affected entity that is used to determine compliance with each affected entity's emissions standard.

(c) If a state has a requirement for hourly CO_2 emissions and net generation information to be used to calculate compliance with an annual emissions standard for affected EGUs, any information that is submitted to the EPA electronically pursuant to requirements in Part 75 would meet the recordkeeping requirement of this section and a state would not need to keep records of information that would be in duplicate of paragraph (b) of this section.

(d) A state must keep records at minimum for 20 years.

§ 60.5815 What are my state reporting requirements?

(a) You must submit an annual report covering each calendar year no later than July 1 of the following year, starting July 1 2021. The annual report must include the following:

(1) The level of emissions performance achieved by all affected entities and identification of whether affected entities are on schedule to meet the applicable level of emissions performance for affected entities during the plan performance period and compliance periods, as specified in the plan.

(2) The level of emissions performance achieved by all affected EGUs during the reporting period, and prior reporting periods, expressed as average CO_2 emissions rate or total mass CO_2 emissions, consistent with the plan approach, and identification of whether affected EGUs are on schedule to meet the applicable level of emissions performance for affected EGUs during the plan performance period, as specified in the plan.

(3) A list of affected entities and their compliance status with the applicable emissions standards specified in the state plan.

(4) A list of all affected EGUs and their reported CO_2 emissions performance for each compliance period during the reporting period, and prior reporting periods.

(5) All other required information, as specified in your state plan according to § 60.5740(a)(9).

(6) All information required by § 60.5775(e).

(b) For each two-year period in § 60.5775(c)(1), you must compare the average CO_2 emission performance achieved by affected entities in the state versus the CO_2 emission performance projected in the state plan. If actual emission performance is greater than 10 percent in excess to projected plan performance for a two-year comparison period, you must explain the reasons for the deviation and specify the corrective actions that will be taken to ensure that the required interim and final levels of emission performance in the plan will be met. The information required in this paragraph must be included in the annual report required by paragraph (a) of this section.

(c) You must include in your 2029 annual report (which is subsequently due by July 1, 2030) the calculation of average emissions over the 2020–2029 interim performance period used to determine compliance with your interim emission performance level. The calculated value must be in units consistent with your interim emission performance level.

(d) You must include in each report, starting with the 2032 annual report (which is subsequently due by July 1, 2033), a 3-calendar year rolling average used to determine compliance with the final emission performance level. The calculated value must be in units consistent with your final emission performance level.

Definitions

§ 60.5820 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein will have the meaning given them in the Clean Air Act and in subparts A (General Provisions) and B of this part.

Affected electric generating unit or *Affected EGU* means a steam generating unit, an IGCC facility, or a stationary combustion turbine that meets the applicability conditions in section § 60.5795.

Affected Entity shall mean any of the following: An affected EGU, or another entity with obligations under this subpart for the purpose of meeting the emissions performance goal requirements in these emission guidelines.

Base load rating means the maximum amount of heat input (fuel) that a steam generating unit can combust on a steady state basis, as determined by the physical design and characteristics of the steam generating unit at ISO conditions. For a stationary combustion turbine, *base load rating* means 100 percent of the design heat input capacity of the simple cycle portion of the stationary combustion turbine at ISO conditions (heat input from duct burners is not included).

CO_2 emissions performance goal means the rate-based CO_2 emissions performance goal specified for a state in Table 1 of this subpart, or a translated mass-based form of that goal.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see § 60.17), coal refuse, and petroleum coke. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

Combined cycle facility means an electric generating unit that uses a stationary combustion turbine from which the heat from the turbine exhaust gases is recovered by a heat recovery steam generating unit to generate additional electricity.

Combined heat and power facility or *CHP facility, (*also known as ''cogeneration'') means an electric generating unit that that use a steam-generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source.

Compliance period means the period of time, set forth by a state in its state plan, during which each affected entity must demonstrate compliance with an applicable emissions standard, and shall be no greater than a three year period for a mass-based plan, and shall be no greater than a one year period for a rate-based plan.

Emission performance level in a state plan means the level of emissions performance for affected entities specified in a state plan, according to § 60.5740.

Emission standard means in addition to the definition in § 60.21, any requirement applicable to any affected entity other than an affected source that has the effect of reducing utilization of one or more affected sources, thereby avoiding emissions from such sources, including, for example, renewable energy and demand-side energy efficiency measures requirements.

Excess emissions means a specified averaging period over which the CO_2 emissions rate is higher than an applicable emissions standard or an averaging period during which an affected EGU is not in compliance with any other emission limitation specified in an emission standard.

Existing state program, requirement, or measure means, in the context of a state plan, a regulation, requirement, program, or measure administered by a state, utility, or other entity that is currently established. This may include a regulation or other legal requirement that includes past, current, and future obligations, or current programs and measures that are in place and are anticipated to be continued or expanded in the future, in accordance with established plans. An existing state program, requirement, or measure may have past, current, and future impacts on EGU CO_2 emissions.

Fossil fuel means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

Gaseous fuel means any fuel that is present as a gas at ISO conditions and includes, but is not limited to, natural gas, refinery fuel gas, process gas, coke-oven gas, synthetic gas, and gasified coal.

Heat recovery steam generating unit (HRSG) means a unit in which hot exhaust gases from the combustion turbine engine are routed in order to extract heat from the gases and generate useful output. Heat recovery steam generating units can be used with or without duct burners.

Integrated gasification combined cycle facility or *IGCC facility* means a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment. The Administrator may waive the 50 percent solid-derived fuel requirement during periods of the gasification system construction, startup and commissioning, shutdown, or repair. No solid fuel is directly burned in the unit during operation.

ISO conditions means 288 Kelvin (15° C), 60 percent relative humidity and 101.3 kilopascals pressure.

Liquid fuel means any fuel that is present as a liquid at ISO conditions and includes, but is not limited to, distillate oil and residual oil.

Mechanical output means the useful mechanical energy that is not used to operate the affected facility, generate electricity and/or thermal output, or to enhance the performance of the affected facility. Mechanical energy measured in horsepower hour should be converted into MWh by multiplying it by 745.7 then dividing by 1,000,000.

Natural gas means a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

Net-electric output means the amount of gross generation the generator(s) produce (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)), as measured at the generator terminals, less the electricity used to operate the plant (i.e., auxiliary loads); such uses include fuel handling equipment, pumps, fans, pollution control equipment, other electricity needs, and transformer losses as measured at the transmission side of the step up transformer (e.g., the point of sale).

Net energy output means:

(1) The net electric or mechanical output from the affected facility, plus 75 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application).

(2) For combined heat and power facilities where at least 20.0 percent of

the total gross energy output consists of electric or direct mechanical output and 20.0 percent of the total gross energy output consists of useful thermal output on a rolling 3 year basis, the net electric or mechanical output from the affected facility divided by 0.95, plus 75 percent of the useful thermal output measured relative to SATP conditions that is not used to generate additional electric or mechanical output or to enhance the performance of the unit (e.g., steam delivered to an industrial process for a heating application).

Petroleum means crude oil or a fuel derived from crude oil, including, but not limited to, distillate and residual oil.

Solid fuel means any fuel that has a definite shape and volume, has no tendency to flow or disperse under moderate stress, and is not liquid or gaseous at ISO conditions. This includes, but is not limited to, coal, biomass, and pulverized solid fuels.

Standard ambient temperature and pressure (SATP) conditions means 298.15 Kelvin (25° C, 77 °F)) and 100.0 kilopascals (14.504 psi, 0.987 atm) pressure. The enthalpy of water at SATP conditions is 50 Btu/lb.

Stationary combustion turbine means all equipment, including but not limited to the turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, fuel compressor, heater, and/or pump, post-combustion emissions control technology, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system plus any integrated equipment that provides electricity or useful thermal output to the combustion turbine engine, heat recovery system or auxiliary equipment. Stationary means that the combustion turbine is not self-propelled or intended to be propelled while performing its function. It may, however, be mounted on a vehicle for portability. If a stationary combustion turbine burns any solid fuel directly it is considered a steam generating unit.

Steam generating unit means any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected facility or auxiliary equipment.

Useful thermal output means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electric generation, mechanical output at the affected facility, or to directly enhance the performance of the affected facility (e.g., economizer output is not useful thermal output, but thermal energy used to reduce fuel moisture is considered useful thermal output). Useful thermal output for affected facilities with no condensate return (or other thermal energy input to the affected facility) or where measuring the energy in the condensate (or other thermal energy input to the affected facility) would not meaningfully impact the emission rate calculation is measured against the energy in the thermal output at SATP conditions. Affected facilities with meaningful energy in the condensate return (or other thermal energy input to the affected facility) must measure the energy in the condensate and subtract that energy relative to SATP conditions from the measured thermal output.

TABLE 1 TO SUBPART UUUU OF PART 60—STATE RATE-BASED CO_2 EMISSION PERFORMANCE GOALS

[Pounds of CO_2 per net MWh]

State	Interim goal	Final goal
Alabama	1,147	1,059
Alaska	1,097	1,003
Arizona	735	702
Arkansas	968	910
California	556	537
Colorado	1,159	1,108
Connecticut	597	540
Delaware	913	841
Florida	794	740
Georgia	891	834
Hawaii	1,378	1,306
Idaho	244	228
Illinois	1,366	1,271
Indiana	1,607	1,531
Iowa	1,341	1,301
Kansas	1,578	1,499
Kentucky	1,844	1,763
Louisiana	948	883
Maine	393	378
Maryland	1,347	1,187
Massachusetts	655	576
Michigan	1,227	1,161
Minnesota	911	873
Mississippi	732	692
Missouri	1,621	1,544
Montana	1,882	1,771
Nebraska	1,596	1,479
Nevada	697	647
New Hampshire	546	486
New Jersey	647	531
New Mexico	1,107	1,048
New York	635	549
North Carolina	1,077	992
North Dakota	1,817	1,783

TABLE 1 TO SUBPART UUUU OF PART 60—STATE RATE-BASED CO_2 EMISSION PERFORMANCE GOALS—Continued

[Pounds of CO_2 per net MWh]

State	Interim goal	Final goal
Ohio	1,452	1,338
Oklahoma	931	895
Oregon	407	372
Pennsylvania	1,179	1,052
Rhode Island	822	782
South Carolina	840	772
South Dakota	800	741
Tennessee	1,254	1,163
Texas	853	791
Utah	1,378	1,322
Virginia	884	810
Washington	264	215
West Virginia	1,748	1,620
Wisconsin	1,281	1,203
Wyoming	1,808	1,714

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Part III

Environmental Protection Agency

40 CFR Part 60

Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units; Proposed Rules

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2013–0603; FRL 9910–00–OAR]

RIN 2060–AR88

Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing standards of performance for emissions of greenhouse gases from affected modified and reconstructed fossil fuel-fired electric utility generating units. Specifically, the EPA is proposing standards to limit emissions of carbon dioxide from affected modified and reconstructed electric utility steam generating units and from natural gas-fired stationary combustion turbines. This rule, as proposed, would continue progress already underway to reduce carbon dioxide emissions from the electric power sector in the United States.

DATES: *Comments on the proposed standards.* Comments on the proposed standards must be received on or before October 16, 2014.

Comments on the information collection request. Under the Paperwork Reduction Act (PRA), since the Office of Management and Budget (OMB) is required to make a decision concerning the information collection request between 30 and 60 days after June 18, 2014, a comment to the OMB is best assured of having its full effect if the OMB receives it by July 18, 2014.

Public Hearing. In a separate action in the **Federal Register**, the EPA is proposing Clean Air Act (CAA) section 111(d) emission guidelines for existing fossil fuel-fired electric utility generating units (EGUs) and is announcing public hearings associated with that action. Because of the interconnected nature of this proposed rulemaking with the proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, we will hold joint hearings on both proposed rulemakings. Please consult the **Federal Register** document proposing Emission Guidelines for Existing Sources for information on public hearings for both actions. Additionally, information for the joint public hearings will be posted on the following Web sites: *http://www2.epa.gov/carbon-pollution-standards* and *http://www2.epa.gov/cleanpowerplan.* If any dates, times or locations of announced public hearings are changed for the proposed emission guidelines, then the public hearing dates, times and locations for this action will also change accordingly. If you would like to speak at the public hearing(s), please register by following instructions provided in the document for the emission guidelines proposed in the **Federal Register**. Please note that written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the public hearing(s).

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2013–0603, by one of the following methods:

At the Web site http://www.regulations.gov: Follow the instructions for submitting comments.

Email: Send your comments by electronic mail (email) to *a-and-r-docket@epa.gov,* Attn: Docket ID No. EPA–HQ–OAR–2013–0603.

Facsimile: Fax your comments to (202) 566–9744, Attn: Docket ID No. EPA–HQ–OAR–2013–0603.

Mail: Send your comments to the EPA Docket Center, U.S. EPA, Mail Code 28221T, 1200 Pennsylvania Ave. NW., Washington, DC 20460, Attn: Docket ID No. EPA–HQ–OAR–2013–0603. Comments on the information collection provisions should be mailed to the Office of Information and Regulatory Affairs, OMB, Attn: Desk Officer for EPA, 725 17th St. NW., Washington, DC 20503.

Hand Delivery or Courier: Deliver your comments to the EPA Docket Center, William Jefferson Clinton Building West, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20004, Attn: Docket ID No. EPA–HQ–OAR–2013–0603. Such deliveries are accepted only during the Docket Center's normal hours of operation (8:30 a.m. to 4:30 p.m., Monday through Friday, excluding Federal holidays), and special arrangements should be made for deliveries of boxed information.

Instructions: All submissions must include the agency name and docket ID number (EPA–HQ–OAR–2013–0603). The EPA's policy is to include all comments received without change, including any personal information provided, in the public docket, available online at *http://www.regulations.gov,* unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. Send or deliver information identified as CBI only to the following address: Roberto Morales, OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, NC 27711, Attention Docket ID No. EPA–HQ–OAR–2013–0603. Clearly mark the information you claim to be CBI. For CBI information on a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information you claim as CBI. In addition to one complete version of the comment that includes information claimed as CBI, you must submit a copy of the comment that does not contain the information claimed as CBI for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

The EPA requests that you also submit a separate copy of your comments to the contact person identified below (see **FOR FURTHER INFORMATION CONTACT**). If the comment includes information you consider to be CBI or otherwise protected, you should send a copy of the comment that does not contain the information claimed as CBI or otherwise protected.

The *www.regulations.gov* Web site is an ''anonymous access'' system, 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 *http://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 disk or CD–ROM 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 avoid the use of special characters, any form of encryption and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *http://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 either electronically at *http://www.regulations.gov* or in hard copy at the EPA Docket Center, William Jefferson Clinton Building West, Room 3334, 1301 Constitution Ave. NW., Washington, DC 20004. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding federal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742. Visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm* for additional information about the EPA's public docket.

In addition to being available in the docket, an electronic copy of this proposed rule will be available on the World Wide Web (WWW). Following signature, a copy of this proposed rule will be posted at the following address: *http://www2.epa.gov/carbon-pollution-standards.*

FOR FURTHER INFORMATION CONTACT: Mr. Christian Fellner, Energy Strategies Group, Sector Policies and Programs Division (D243–01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919)541–4003, facsimile number (919)541–5450; email address: *fellner.christian@epa.gov* or Dr. Nick Hutson, Energy Strategies Group, Sector Policies and Programs Division (D243–01), U.S. EPA, Research Triangle Park, NC 27711; telephone number (919)541–2968, facsimile number (919)541–5450; email address: *hutson.nick@epa.gov.*

SUPPLEMENTARY INFORMATION:

Acronyms. A number of acronyms and chemical symbols are used in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined as follows:

AEO Annual Energy Outlook
APPA American Public Power Association
BSER Best System of Emission Reduction
CAA Clean Air Act
CAP Climate Action Plan
CBI Confidential Business Information
CCS Carbon Capture and Storage (or Sequestration)
CFB Circulating Fluidized Bed
CH_4 Methane
CHP Combined Heat and Power
CO_2 Carbon Dioxide
DOE/NETL Department of Energy/National Energy Technology Laboratory
EGU Electric Utility Generating Unit
EO Executive Order
EPA Environmental Protection Agency
FB Fluidized Bed
FR Federal Register
GHG Greenhouse Gas
HFC Hydrofluorocarbon
HRSG Heat Recovery Steam Generator
ICR Information Collection Request
IGCC Integrated Gasification Combined Cycle
IPCC Intergovernmental Panel on Climate Change
lb CO_2/MWh Pounds of CO_2 per Megawatt-hour
lb CO_2/MWh-net Pounds of CO_2 per Megawatt-hour on a net output basis
LCOE Levelized Cost of Electricity
MMBtu/h Million British Thermal Units per Hour
MPa Megapascal
MW Megawatt
MWe Megawatt Electrical
MWh Megawatt-hour
N_2 Nitrogen Gas
N_2O Nitrous Oxide
NO_X Nitrogen Oxide
NAICS North American Industry Classification System
NGCC Natural Gas Combined Cycle
NGR Natural Gas Reburning
NRC National Research Council
NRECA National Rural Electric Cooperative Association
NSPS New Source Performance Standards
NTTAA National Technology Transfer and Advancement Act
OFA Overfire Air
OMB Office of Management and Budget
PC Pulverized Coal
PFC Perfluorocarbons
$PM_{2.5}$ Particular Matter less than 2.5 micrometer in diameter
PRA Paperwork Reduction Act
psi Pounds per square inch
psig Pounds per square inch-guage
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
SBA Small Business Administration
SCC Social cost of carbon
SCPC Supercritical pulverized coal
SF_6 Sulfur Hexafluoride
SO_2 Sulfur dioxide
Tg Teragram (one trillion (10^{12}) grams)
TSD Technical Support Document
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States
USGCRP U.S. Global Change Research Program
VCS Voluntary Consensus Standard
WWW Worldwide Web

Organization of This Document. The information presented in this preamble is organized as follows:

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I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

On June 25, 2013, in conjunction with the announcement of his Climate Action Plan (CAP), President Obama issued a Presidential Memorandum directing the EPA to issue a new proposal to address carbon pollution from new power plants by September 30, 2013, and to issue ''standards, regulations, or guidelines, as appropriate, which address carbon pollution from modified, reconstructed, and existing power plants.'' Consistent with the Presidential Memorandum, on September 20, 2013, the Administrator signed proposed carbon pollution standards for newly constructed fossil fuel-fired power plants. The proposal was published on January 8, 2014 (79 FR 1430; January 2014 proposal). Specifically, under the authority of CAA section 111(b), the EPA proposed new source performance standards (NSPS) to limit emissions of carbon dioxide (CO_2) from newly constructed fossil fuel-fired electric utility steam generating units (utility boilers and integrated gasification combined cycle (IGCC) units) and newly constructed natural gas-fired stationary combustion turbines.

In this action, under the authority of CAA section 111(b), the EPA is proposing standards of performance to limit emissions of CO_2 from modified and reconstructed fossil fuel-fired electric utility steam generating units and natural gas-fired stationary combustion turbines. Specifically, the EPA is proposing standards of performance for: (1) Modified fossil fuel-fired utility boilers and IGCC units, (2) modified natural gas-fired stationary combustion turbines, (3) reconstructed fossil fuel-fired utility boilers and IGCC units, and (4) reconstructed natural gas-fired stationary combustion turbines. Consistent with the requirements of CAA section 111(b), these proposed standards reflect the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) that the EPA has determined has been adequately demonstrated for each type of unit.

In a separate action, under CAA section 111(d), the EPA is proposing emission guidelines for states to use in developing plans to limit CO_2 emissions from existing fossil fuel-fired EGUs. States must then submit plans to the EPA under timing set by that action.

2. Summary of the Major Provisions

The proposed standards for the affected modified and reconstructed sources are summarized below in Table 1.

TABLE 1—SUMMARY OF BSER AND PROPOSED STANDARDS FOR AFFECTED SOURCES

Affected source	BSER	Standard
Modified Utility Boilers and IGCC Units.	Most efficient generation at the affected source achievable through a combination of best operating practices and equipment upgrades.	**Co-proposed Alternative #1** 1. Source would be required to meet a unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification) plus an additional 2 percent emission reduction; the emission limit will be no lower than: a. 1,900 lb CO_2/MWh-net for sources with heat input >2,000 MMBtu/h. OR b. 2,100 lb CO_2/MWh-net for sources with heat input ≤2,000 MMBtu/h.
Modified Utility Boilers and IGCC Units.	Most efficient generation at the affected source achievable through a combination of best operating practices and equipment upgrades.	**Co-proposed Alternative #2** Source would be required to meet a unit-specific emission limit dependent upon when the modification occurs. 1. Sources that modify prior to becoming subject to a CAA 111(d) plan would be required to meet a unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to date of the modification) plus an additional 2 percent emission reduction; the emission limit will be no lower than: a. 1,900 lb CO_2/MWh-net for sources with heat input >2,000 MMBtu/h. OR b. 2,100 lb CO_2/MWh-net for sources with heat input ≤2,000 MMBtu/h. 2. Sources that modify after becoming subject to a CAA 111(d) plan would be required to meet a unit-specific emission limit determined by the 111(b) implementing authority from the results of an energy efficiency improvement audit.
Modified Natural Gas-Fired Stationary Combustion Turbines.	Efficient NGCC technology	1. Sources with heat input >850 MMBtu/h would be required to meet an emission limit of 1,000 lb CO_2/MWh-gross. 2. Sources with heat input ≤850 MMBtu/h would be required to meet an emission limit of 1,100 lb CO_2/MWh-gross.
Reconstructed Utility Boilers and IGCC Units.	Most efficient generating technology at the affected source.	1. Sources with heat input >2,000 MMBtu/h would be required to meet an emission limit of 1,900 lb CO_2/MWh-net. 2. Sources with heat input ≤2,000 MMBtu/h would be required to meet an emission limit of 2,100 lb CO_2/MWh-net.
Reconstructed Natural Gas-Fired Stationary Combustion Turbines.	Efficient NGCC technology	1. Sources with heat input >850 MMBtu/h would be required to meet an emission limit of 1,000 lb CO_2/MWh-gross. 2. Sources with heat input ≤850 MMBtu/h would be required to meet an emission limit of 1,100 lb CO_2/MWh-gross.

For the reasons discussed in the ''Legal Memorandum'' [1] supporting document in the docket for the rulemaking for CO_2 emissions from existing EGUs under CAA section 111(d), all existing sources that become modified or reconstructed sources and which are subject to a CAA section 111(d) plan at the time of the modification or reconstruction, will remain in the CAA section 111(d) plan and remain subject to any applicable regulatory requirements in the plan, in addition to being subject to regulatory requirements under CAA section 111(b).

It should be noted that the EPA intends each standard of performance proposed in this rulemaking to be severable from each other standard of performance, such that if one or more of the standards of performance were to be remanded or vacated in a court challenge, the EPA intends for the other standards to remain in effect. The EPA also intends each BSER determination or alternative determination, as applicable, for modified utility boilers and IGCC units, and for modified natural gas-fired stationary combustion turbines, to be severable from each other BSER determination. In all of these cases, the EPA believes that the standards of performance and associated best systems of emission reduction operate independently of each other.[2] The EPA also intends that the standards applicable to the units that modify after the unit is subject to a 111(d) plan are severable and that if those standards were over-turned, the standards applicable to units that modify when they are not subject to a 111(d) plan would apply to all modified sources, regardless of the timing of their modification.

The EPA is proposing that the form of the standards for modified and reconstructed natural gas-fired stationary combustion turbines be consistent with the standards for newly constructed natural gas-fired stationary combustion turbines proposed on January 8, 2014 (79 FR 1430). In that proposal, the EPA proposed standards for turbines on a gross output basis, but also took comment on standards on a net output basis. The EPA is similarly proposing standards on a gross output basis, while soliciting comment on net output based standards, in today's proposal for modified and reconstructed natural gas-fired stationary combustion turbines. To the extent that the EPA finalizes modified and reconstructed standards for stationary combustion turbines that are consistent with the standards for newly constructed stationary combustion turbines, the EPA intends to take the same approach with regards to the use of net or gross output in both final actions.

3. Costs and Benefits

As explained in the regulatory impact analysis (RIA) [3] for this proposed rule and further below, the EPA expects few units would trigger either the modification or the reconstruction provisions that we are proposing today. Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative modified unit. Based on the analysis, the EPA projects that this proposed rule will result in potential CO_2 emission changes, quantified benefits, and costs for a unit that is subject to the modification provision. In this illustrative example, based on a hypothetical 500 MW coal-fired unit, we estimate costs, net of fuel savings, of $0.78 million to $4.5 million (2011$) and CO_2 reductions of 133,000 to 266,000 tons in 2025. The climate benefits from reductions in CO_2, combined with the health co-benefits from reductions in sulfur dioxide (SO_2), nitrogen oxides (NO_X), and fine particulate matter ($PM_{2.5}$), total $18 to $33 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the lowest emission reduction scenario, and $35 to $65 million ($2011) at a 3 percent discount rate for emission reductions in 2025 for the highest emission reduction scenario.[4]

B. Overview

1. What authority is the EPA relying on to address power plant CO_2 emissions?

The U.S. Supreme Court ruled, in *Massachusetts* v. *EPA,* that greenhouse gases (GHGs) [5] meet the definition of ''air pollutant'' in the CAA,[6] and premised its decision in *AEP* v. *Connecticut* [7] that the CAA displaced any federal common law right to compel reductions in CO_2 emissions from fossil fuel-fired power plants on its view that CAA section 111 applies to GHG emissions.

Congress established requirements under section 111 of the 1970 CAA to control air pollution from new stationary sources through NSPS. Specifically, as explained in greater detail in section II below, CAA section 111(b) authorizes the EPA to set ''standards of performance'' for new (including modified) stationary sources from listed source categories to limit emissions of air pollutants to the environment, and the EPA's implementing regulations provide that new sources include reconstructed sources.[8] Under CAA section 111(a)(1), the EPA must set these standards at the level of emission reduction that reflects the ''best system of emission reduction . . . adequately demonstrated,'' taking into account technical feasibility, costs, and other factors.

For more than four decades, the EPA has used its authority under CAA section 111 to set cost-effective emission standards that ensure newly constructed, reconstructed and modified stationary sources use the best performing technologies to limit emissions of harmful air pollutants. In this proposal, the EPA is following the same well-established interpretation and application of the law under CAA section 111 to address GHG emissions from modified and reconstructed fossil fuel-fired electric steam generating units and natural gas-fired stationary combustion turbines.

2. What sources would be regulated by the proposed standards?

The proposed standards of performance would regulate GHG emissions from modified and reconstructed (1) fossil fuel-fired electric steam generating units—utility boilers and IGCC units—whose non-

[1] The ''Legal Memorandum'' supporting document is available in the rulemaking docket for the proposed emission guidelines for existing source power plants, Docket ID: EPA–HQ–OAR–2013–0602.''

[2] *See K Mart Corp.* v. *Cartier, Inc.,* 486 U.S. 281, 294 (1988) (holding that a regulation was severable because the ''[t]he severance and invalidation of [the subsection at issue would] not impair the function of the statute as a whole, and there [was] no indication that the regulation would not have been passed but for its inclusion.'').

[3] The RIA for this proposal is presented as Chapter 9 of the RIA for the companion rulemaking for proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.

[4] For purposes of this summary, we present climate benefits from CO_2 that were estimated using the model average social cost of carbon (SCC) at a 3 percent discount rate. We emphasize the importance and value of considering the full range of SCC values, however, which include the model average at 2.5 and 5 percent, and the 95th percentile at 3 percent. Similarly, we summarize the health co-benefits in this summary at a 3 percent discount rate. We provide estimates based on additional discount rates in the RIA.

[5] Greenhouse gas pollution is the aggregate group of the following gases: CO_2, methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

[6] 549 U.S. 497, 520 (2007).

[7] 131 S.Ct. 2527, 2537–38 (2011).

[8] 40 CFR part 60 subpart A

GHG emissions are regulated under 40 CFR part 60, subpart Da, and (2) natural gas-fired stationary combustion turbines, whose non-GHG emissions are regulated under 40 CFR part 60, subpart KKKK. Natural gas-fired stationary combustion turbines that supply less than one-third of their potential electric output to the grid are not subject to standards in today's proposal.

The CAA and the EPA's implementing regulations define a ''modification,'' for purposes of NSPS applicability, as a physical or operational change that increases the source's maximum achievable hourly rate of emissions, with certain exceptions.[9]

Under the EPA's 1975 framework regulations covering CAA section 111 standards of performance, ''reconstruction'' means the replacement of components of an existing facility to an extent that (1) 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 (2) it is technologically and economically feasible to meet the applicable standards.[10]

3. Why is the EPA issuing this proposed rule?

GHG pollution threatens the American public's health and welfare by contributing to long-lasting changes in our climate system that can have a range of negative effects on human health and the environment. The impacts could include: Longer, more intense and more frequent heat waves; more intense precipitation events and storm surges; less precipitation and more prolonged droughts in the West and Southwest; increased frequency and severity of short-term droughts in some other U.S. regions; more fires and insect pest outbreaks in American forests, especially in the West; and increased ground level ozone pollution, otherwise known as smog, which has been linked to asthma and premature death. Health risks from climate change are especially serious for children, the elderly and those with heart and respiratory problems.

Unlike most other air pollutants, GHGs may persist in the atmosphere from decades to millennia, depending on the specific GHG. This special characteristic makes it crucial to act now to limit GHG emissions from fossil fuel-fired power plants, specifically emissions of CO_2, since they are the nation's largest sources of carbon pollution.

As previously noted, on June 25, 2013, President Obama issued a Presidential Memorandum directing the EPA to address carbon pollution from the power sector. As an initial step to limit carbon pollution from power plants, on January 8, 2014, the EPA published a proposed rule to limit GHG emissions from newly constructed fossil fuel-fired electric steam generating units (utility boilers and IGCC units) and newly constructed natural gas-fired stationary combustion turbines. The EPA is now taking another step to limit carbon pollution in this country by issuing a proposed rule to limit GHG emissions from modified and reconstructed fossil fuel-fired electric steam generating units and modified and reconstructed natural gas-fired stationary combustion turbines.

Although we expect that the modification and reconstruction standards of performance in this rulemaking will apply to few sources—since there have been a limited number in the past—these standards serve another important purpose that may affect a larger number of sources: Providing an incentive, and the information needed, for existing sources to structure their actions to achieve their operating and business goals without triggering the modification or reconstruction standards. For example, the modification standard encourages existing sources that undertake physical or operational changes to do so in a manner that does not increase their emission rate.

4. What is the EPA's approach to setting standards for modified and reconstructed EGUs under CAA section 111(b)?

CAA section 111(b) requires the EPA to establish standards of performance that reflect the degree of emission limitation that is achievable through the application of the ''best system of emission reduction'' which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the EPA determines has been adequately demonstrated. The text and legislative history of CAA section 111, as well as relevant court decisions identify the factors for the EPA to consider in making a BSER determination. They include, among others, whether the system of emission reduction is technically feasible, whether the costs of the system are reasonable, the amount of emissions reductions that the system would generate, and whether the standard would effectively promote further deployment or development of advanced technologies. The case law addressing section 111 makes it clear that the EPA has discretion in weighing these factors, and that as a result, the EPA may weigh them differently for different types of sources or air pollutants. See further discussion of this case law in section VI below.

For each of the standards being proposed in today's action, the EPA considered a number of alternatives and evaluated them against the factors.

The BSER we are proposing for each category of affected sources and the proposed standards of performance based on these BSER—as described immediately below—are based on that evaluation, as discussed in sections VI–IX below.

5. What are the BSER and the standard of performance for modified fossil fuel-fired utility boilers and IGCC units?

The EPA proposes that the BSER for modified fossil fuel-fired boilers and IGCC units is each unit's own best potential performance based on a combination of best operating practices and equipment upgrades. Specifically, the EPA is proposing unit-specific emission standards consistent with this BSER determination and is co-proposing two alternative standards for modified utility steam generating units. In the first co-proposed alternative, modified utility boilers and IGCC units would be subject to a single emission standard. Specifically, under the first co-proposed alternative, a modified source would be required to meet a unit-specific emission limit determined by the affected source's best demonstrated historical performance (in the years from 2002 to the time of the modification) with an additional 2 percent emission reduction. The EPA has determined that this standard can be met through a combination of best operating practices and equipment upgrades. To account for facilities that have already implemented best practices and equipment upgrades, the proposal also specifies that modified facilities would not have to meet an emission standard more stringent than the corresponding standard for reconstructed EGUs. The EPA also solicits comment on whether, for units that have become subject to a CAA section 111(d) plan, the period of best historical performance should be the years from 2002 to the time when the unit becomes subject to the CAA section 111(d) plan, rather than to the time of the modification. This could address the concern that sources that make improvements to their CO_2 emission

[9] CAA Section 111(a)(4); 40 CFR 60.2, 60.14.

[10] 40 CFR 60.15(b).

rate as a result of a CAA section 111(d) plan would have lower baseline emissions from which to calculate their required rate.

It is our interpretation that, as we discuss in detail in the Legal Memorandum,[11] an existing source would continue to be subject to CAA section 111(d) requirements after it becomes a modified source, whether the modification occurs before or after the promulgation of a CAA section 111(d) plan. Therefore EPA is co-proposing that modified sources would be required to meet unit-specific emission standards that would depend on the timing of the modification. Sources that modify prior to becoming subject to a CAA section 111(d) plan would be required to meet the same standard described in the first co-proposal—that is, the modified source would be required to meet a unit-specific emission limit determined by the affected source's best demonstrated historical performance (in the years from 2002 to the time of the modification) with an additional 2 percent emission reduction (based on equipment upgrades). Sources that modify after becoming subject to a CAA section 111(d) plan would be required to meet a unit-specific emission limit that would be determined by the CAA section 111(d) implementing authority and would be based on the source's expected performance after implementation of identified unit-specific energy efficiency improvement opportunities. The BSER and standards of performance for modified fossil-fired electric utility steam generating units are discussed further in section VII of this preamble.

6. What is the BSER and standard of performance for modified natural gas-fired stationary combustion turbines?

For modified natural gas-fired stationary combustion turbines, the EPA is proposing standards of performance based on efficient Natural Gas Combined Cycle (NGCC) technology as the BSER. The emission limits proposed for these sources are 1,000 lb CO_2/MWh-gross for facilities with heat input ratings greater than 850 MMBtu/h, and 1,100 lb CO_2/MWh-gross for facilities with heat input ratings of 850 MMBtu/h or less. For sources that are subject to a CAA section 111(d) plan, the EPA is also soliciting comment on whether the sources should be allowed to elect, as an alternative to the otherwise applicable numeric standard, to instead meet a unit-specific emission standard that is determined by the CAA section 111(d) implementing authority based on implementation of identified energy efficiency improvement opportunities applicable to the source. This is discussed further in section IX of this preamble.

7. What are BSER and the standard of performance for reconstructed fossil fuel-fired utility boilers and IGCC units?

For reconstructed utility boilers and IGCC units, the EPA is proposing a standard of performance with BSER based on the most efficient generating technology for these types of units (i.e., reconstructing the boiler to use higher steam, temperature and pressure, even if the boiler was not originally designed to do so [12]). The proposed emission limit for these sources is 1,900 lb CO_2/MWh-net for sources with a heat input rating of greater than 2,000 MMBtu/h or 2,100 lb CO_2/MWh-net for sources with a heat input rating of 2,000 MMBtu/h or less. The difference in the proposed standards for larger and smaller units is based on greater availability of higher pressure/temperature steam turbines (e.g. supercritical steam turbines) for larger units. The standards could also be met through other technology options such as natural gas co-firing. This is discussed further in section VI below.

As discussed in the Legal Memorandum,[13] a reconstruction would have no effect on the applicability of an approved CAA section 111(d) plan; thus, a source that is subject to requirements in a CAA section 111(d) plan would remain subject to those requirements.

8. What are BSER and the standard of performance for reconstructed natural gas-fired stationary combustion turbines?

The EPA is proposing to find efficient NGCC technology to be the BSER for reconstructed stationary combustion turbines. Therefore, the EPA is proposing that larger units be required to meet a standard of 1,000 lb CO_2/MWh-gross and that smaller units be required to meet a standard of 1,100 lb CO_2/MWh-gross. This is discussed further in section VIII below.

A reconstruction would have no effect on the applicability of an approved CAA section 111(d) plan on the existing source; thus, a source that is subject to requirements in a CAA section 111(d) plan would remain subject to those requirements, even after reconstruction.

9. How is EPA proposing to codify the requirements?

In the January 2014 proposal of carbon pollution standards for newly constructed power plants (79 FR 1430), the EPA co-proposed two options for codifying applicable requirements for covered sources. Under the first option the EPA proposed to codify the standards of performance for the respective sources within existing 40 CFR part 60 subparts so that applicable GHG standards for electric utility steam generating units would be included in subpart Da and applicable GHG standards for stationary combustion turbines would be included in subpart KKKK. Under the second option, the EPA co-proposed to create a new subpart TTTT and to include all GHG standards of performance for covered sources in that newly created subpart.

In this action for modified and reconstructed sources, the EPA co-proposes the same two options for codifying the applicable standards. For consistency, the EPA intends—when it takes final action on this proposal and on the January 2014 proposal for newly constructed sources, respectively—to codify the standards in the same way for the sources addressed under the two proposals.

10. What is the organization and approach for this proposal?

Section II of this preamble provides a brief summary of background information on climate change impacts of GHG emissions, GHG emissions from fossil-fuel fired EGUs, the utility power sector, the statutory and regulatory background relevant to this rulemaking, and the EPA's stakeholder outreach activities. Section II also contains additional information on the regulatory and litigation history of CAA section 111.

The specific proposed requirements for modified and reconstructed sources are described in detail in section III of this preamble. The rationale for reliance on a rational basis to regulate GHG emissions from fossil fuel-fired EGUs and the rationale for the applicability requirements in today's proposal are presented in sections IV and V of this preamble, respectively. Sections VI through IX of this preamble describe the rationale for each of the proposed emission standards, including an explanation of the determination of the BSER for reconstructed fossil fuel-fired utility boilers and IGCC units and modified fossil fuel-fired utility boilers and IGCC units, as well as for

[11] "Legal Memorandum for Proposed Carbon Pollution Guidelines for Existing Power Plants" Technical Support Document available in rulemaking docket ID: EPA–HQ–OAR–2013–0602.

[12] Steam with higher temperature and pressure has more thermal energy which can be more efficiently converted to electrical energy.

[13] Legal Memorandum available in rulemaking docket ID: EPA–HQ–OAR–2013–0602.

reconstructed natural gas-fired stationary combustion turbines and modified natural gas-fired stationary combustion turbines. Impacts of the proposed action are described in section X of this preamble. A discussion of statutory and executive order reviews is provided in section XI of this preamble, and the statutory authority for this action is provided in section XII of this preamble.

It should be noted that this rulemaking overlaps in certain respects with two other related rulemakings: The January 2014 proposed rulemaking for CO_2 emissions from newly constructed affected EGUs, and the rulemaking for existing EGUs that the EPA is proposing at the same time as the present rulemaking. In a number of places in this preamble, the EPA cross-references parts of those two rulemakings. However, each of these three rulemakings is independent of the other two, and each has its own rulemaking docket. Accordingly, anyone who wishes to comment on any aspect of this rulemaking, including anything described by a cross-reference to one of the other two related rulemakings, should make those comments on this rulemaking.

C. Does this action apply to me?

The entities potentially affected by the proposed standards are shown in Table 2 below.

TABLE 2—POTENTIALLY AFFECTED ENTITIES [a]

Category	NAICS code	Examples of potentially affected entities
Industry	221112	Fossil fuel electric power generating units.
Federal Government	[b] 221112	Fossil fuel electric power generating units owned by the federal government.
State/Local Government	[b] 221112	Fossil fuel electric power generating units owned by municipalities.
Tribal Government	921150	Fossil fuel electric power generating units in Indian Country.

[a] Includes North American Industry Classification (NAICS) categories for source categories that own and operate electric power generating units (including boilers and stationary combined cycle combustion turbines).

[b] Federal, state or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by this proposed action. To determine whether your facility, company, business, or organization, would be regulated by this proposed action, you should examine the applicability criteria in 40 CFR 60.1. If you have any questions regarding the applicability of this action to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative as listed in 40 CFR 60.4 (General Provisions).

II. Background

In this section,[14] we discuss climate change impacts from GHG emissions, both on public health and public welfare, present information about GHG emissions from fossil-fuel fired EGUs, describe the utility power sector and summarize the statutory and regulatory background relevant to this rulemaking. We close this section by describing stakeholder outreach and a brief history of modifications and reconstructions in the power sector.

A. Climate Change Impacts From GHG Emissions

In 2009, the EPA Administrator issued the document known as the Endangerment Finding under CAA section 202(a)(1).[15] In the Endangerment Finding, which focused on public health and public welfare impacts within the United States, the Administrator found that elevated concentrations of GHGs in the atmosphere may reasonably be anticipated to endanger public health and welfare of current and future generations. We summarize these adverse effects on public health and welfare briefly here.[16]

1. Public Health Impacts Detailed in the 2009 Endangerment Finding [17]

Climate change caused by human emissions of GHGs threatens public health in multiple ways. By raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the United States. Compared to a future without climate change, climate change is expected to increase ozone pollution over broad areas of the U.S., including in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality. Other public health threats also stem from projected increases in intensity or frequency of extreme weather associated with climate change, such as increased hurricane intensity, increased frequency of intense storms, and heavy precipitation. Increased coastal storms and storm surges due to rising sea levels are expected to cause increased drownings and other health impacts. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

2. Public Welfare Impacts Detailed in the 2009 Endangerment Finding [18]

Climate change caused by human emissions of GHGs also threatens public welfare in multiple ways. Climate changes are expected to place large areas of the country at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas are expected to

[14] This background section is intended to provide the same or very similar background information as provided in the companion proposals for new sources (79 FR 1430) and existing sources (the CAA section 111(d) proposal in today's **Federal Register**). Any minor differences in phrasing between this proposal and the companion proposals are not intended to state a substantive difference.

[15] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,'' 74 FR 66496 (December 15, 2009) (''Endangerment Finding'').

[16] The January 8, 2014, preamble to the proposed GHG standards for new EGUs (79 FR 1430) and the RIA supporting that proposal include a more detailed summary of the public health and welfare impacts detailed in the 2009 Endangerment Finding, as well as a discussion of the science supporting the EPA's conclusions regarding the question of whether GHG endanger public health and welfare including: (1) The process by which the Administrator reached the Endangerment Finding in 2009; (2) the EPA's response in 2010 to ten administrative petitions for reconsideration of the Endangerment Finding (the Reconsideration Denial); and (3) the decision by the United States Court of Appeals for the District of Columbia Circuit in 2012 to uphold the Endangerment Finding and the Reconsideration Denial.

[17] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act,'' 74 FR 66496 (Dec. 15, 2009) (''Endangerment Finding'').

[18] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act,'' 74 FR 66496 (Dec. 15, 2009) (''Endangerment Finding'').

face increased risks from storm and flooding damage to property, as well as adverse impacts from rising sea level, such as land loss due to inundation, erosion, wetland submergence and habitat loss. Climate change is expected to result in an increase in peak electricity demand, and extreme weather from climate change threatens energy, transportation, and water resource infrastructure. Climate change may exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities. Climate change also is very likely to fundamentally rearrange U.S. ecosystems over the 21st century. Though some benefits may balance adverse effects on agriculture and forestry in the next few decades, the body of evidence points towards increasing risks of net adverse impacts on U.S. food production, agriculture and forest productivity as temperature continues to rise. These impacts are global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S.

3. New Scientific Assessments

As outlined in Section VIII.A. of the 2009 Endangerment Finding, the EPA's approach to providing the technical and scientific information to inform the Administrator's judgment regarding the question of whether GHGs endanger public health and welfare was to rely primarily upon the recent, major assessments by the U.S. Global Change Research Program (USGCRP), the Intergovernmental Panel on Climate Change (IPCC), and the National Research Council (NRC) of the National Academies. These assessments addressed the scientific issues that the EPA was required to examine, were comprehensive in their coverage of the GHG and climate change issues, and underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of U.S. government review. Since the administrative record concerning the Endangerment Finding closed following the EPA's 2010 Reconsideration Denial, a number of such assessments have been released. These assessments include the IPCC's 2012 ''Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation'' (SREX) and the 2013–2014 Fifth Assessment Report (AR5), the USGCRP's 2014 ''Climate Change Impacts in the United States'' (Climate Change Impacts), and the NRC's 2010 ''Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean'' (Ocean Acidification), 2011 ''Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia'' (Climate Stabilization Targets), 2011 ''National Security Implications for U.S. Naval Forces'' (National Security Implications), 2011 ''Understanding Earth's Deep Past: Lessons for Our Climate Future'' (Understanding Earth's Deep Past), 2012 ''Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future'', 2012 ''Climate and Social Stress: Implications for Security Analysis'' (Climate and Social Stress), and 2013 ''Abrupt Impacts of Climate Change'' (Abrupt Impacts) assessments.

The EPA has reviewed these new assessments and finds that the improved understanding of the climate system they present strengthens the case that GHGs endanger public health and welfare.

In addition, these assessments highlight the urgency of the situation as the concentration of CO_2 in the atmosphere continues to rise. Absent a reduction in emissions, a recent NRC assessment projected that concentrations by the end of the century would increase to levels that the Earth has not experienced for millions of years.[19] In fact, that assessment stated that ''the magnitude and rate of the present greenhouse gas increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in Earth history.'' [20]

What this means, as stated in another NRC assessment, is that:

> Emissions of carbon dioxide from the burning of fossil fuels have ushered in a new epoch where human activities will largely determine the evolution of Earth's climate. Because carbon dioxide in the atmosphere is long lived, it can effectively lock Earth and future generations into a range of impacts, some of which could become very severe. Therefore, emission reductions choices made today matter in determining impacts experienced not just over the next few decades, but in the coming centuries and millennia.[21]

Moreover, due to the time-lags inherent in the Earth's climate, the Climate Stabilization Targets assessment notes that the full warming from any given concentration of CO_2 reached will not be realized for several centuries.

The recently released USGCRP ''National Climate Assessment'' [22] emphasizes that climate change is already happening now and it is happening in the United States. The assessment documents the increases in some extreme weather and climate events in recent decades, the damage and disruption to infrastructure and agriculture, and projects continued increases in impacts across a wide range of peoples, sectors, and ecosystems.

These assessments underscore the urgency of reducing emissions now: Today's emissions will otherwise lead to raised atmospheric concentrations for thousands of years, and raised Earth system temperatures for even longer. Emission reductions today will benefit the public health and public welfare of current and future generations.

Finally, it should be noted that the concentration of CO_2 in the atmosphere continues to rise dramatically. In 2009, the year of the Endangerment Finding, the average concentration of CO_2 as measured on top of Mauna Loa was 387 parts per million (ppm).[23] The average concentration in 2013 was 396 ppm. And the monthly concentration in April of 2014 was 401 ppm, the first time a monthly average has exceeded 400 ppm since record keeping began at Mauna Loa in 1958, and for at least the past 800,000 years according to ice core records.[24]

B. GHG Emissions From Fossil Fuel-Fired EGUs

Fossil fuel-fired EGUs are by far the largest emitters of GHGs, primarily in the form of CO_2, among stationary sources in the U.S., and among fossil fuel-fired units, coal-fired units are by far the largest emitters. This section describes the amounts of those emissions and places those amounts in the context of the national inventory of GHGs.

The EPA prepares the official U.S. Inventory of Greenhouse Gas Emissions and Sinks [25] (the U.S. GHG Inventory) to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). This inventory, which includes recent trends, is organized by industrial sectors. It provides the information in Table 3 below, which presents total U.S.

[19] National Research Council, Understanding Earth's Deep Past, p. 1.

[20] Id., p.138.

[21] National Research Council, Climate Stabilization Targets, p. 3.

[22] U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment, May 2014 Available at *http://nca2014.globalchange.gov/*.

[23] *ftp://aftp.cmdl.noaa.gov/products/trends/co2/co2_annmean_mlo.txt*.

[24] *http://www.esrl.noaa.gov/gmd/ccgg/trends/*.

[25] ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

anthropogenic emissions and sinks [26] of GHGs, including CO_2 emissions, for the years 1990, 2005 and 2012.

GHGs, including CO_2 emissions, for the years 1990, 2005 and 2012.

TABLE 3—U.S. GHG EMISSIONS AND SINKS BY SECTOR

[Teragram carbon dioxide equivalent (Tg CO_2 Eq.)] [27]

Sector	1990	2005	2012
Energy	5,260.1	6,243.5	5,498.9
Industrial Processes	316.1	334.9	334.4
Solvent and Other Product Use	4.4	4.4	4.4
Agriculture	473.9	512.2	526.3
Land Use, Land-Use Change and Forestry	13.7	25.5	37.8
Waste	165.0	133.2	124.0
Total Emissions	6,233.2	7,253.8	6,525.6
Land Use, Land-Use Change and Forestry (Sinks)	(831.3)	(1,030.7)	(979.3)
Net Emissions (Sources and Sinks)	5,402.1	6,223.1	5,546.3

Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 77.7 percent of total 2012 GHG emissions.[28] In 2012, fossil fuel combustion by the electric power sector—entities that burn fossil fuel and whose primary business is the generation of electricity—accounted for 38.7 percent of all energy-related CO_2 emissions.[29] Table 4 below presents total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2005 and 2012.

TABLE 4—U.S. GHG EMISSIONS FROM GENERATION OF ELECTRICITY FROM COMBUSTION OF FOSSIL FUELS (TG CO_2) [30]

GHG Emissions	1990	2005	2012
Total CO_2 from fossil fuel combustion EGUs	1,820.8	2,402.1	2,022.7
—from coal	1,547.6	1,983.8	1,511.2
—from natural gas	175.3	318.8	492.2
—from petroleum	97.5	99.2	18.8

C. The Utility Power Sector

Electricity in the United States is generated by a range of sources—from power plants that use fossil fuels like coal, oil, and natural gas, to non-fossil sources, such as nuclear, solar, wind and hydroelectric power. In 2013, over 67 percent of power in the U.S. was generated from the combustion of coal, natural gas, and other fossil fuels, over 40 percent from coal and over 26 percent from natural gas.[31] In recent years, though, the proportion of new renewable generation coming on line has increased dramatically. For instance, over 38 percent of new generating capacity (over 5 GW out of 13.5 GW) built in 2013 used renewable power generation technologies.[32]

Natural gas-fired EGUs typically use one of two technologies: NGCC or simple cycle combustion turbines. NGCC units first generate power from a combustion turbine (the combustion cycle). The unused heat from the combustion turbine is then routed to a heat recovery steam generator (HRSG) that generates steam which is used to produce power using a steam turbine (the steam cycle). Combining these generation cycles increases the overall efficiency of the system. Simple cycle combustion turbines use a single combustion turbine to produce electricity (i.e., there is no heat recovery). The power output from these simple cycle combustion turbines can be easily ramped up and down making them ideal for ''peaking'' operations.

Coal-fired utility boilers are primarily either pulverized coal (PC) boilers or fluidized bed (FB) boilers. At a PC boiler, the coal is crushed (pulverized) into a powder in order to increase its surface area. The coal powder is then blown into a boiler and burned. In a coal-fired boiler using FB combustion, the coal is burned in a layer of heated particles suspended in flowing air.

Power can also be generated using gasification technology. An IGCC unit gasifies coal or petroleum coke to form a syngas composed of carbon monoxide and hydrogen, which can be combusted in a combined cycle system to generate power.

D. Statutory Background

CAA section 111 authorizes the EPA to prescribe new source performance standards (NSPS) applicable to certain new stationary sources (including

[26] Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep sea reservoirs of carbon dioxide.

[27] From Table ES–4 of ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012, Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[28] From Table ES–2 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[29] From Table 3–1 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[30] From Table 3–5 ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012'', Report EPA 430–R–14–003, United States Environmental Protection Agency, April 15, 2014.

[31] U.S. Energy Information Administration (EIA), ''Table 7.2b Electricity Net Generation: Electric Power Sector Electric Power Sector,'' data from April 2014 Monthly Energy Review, release date April 25, 2014. Available at: *http://www.eia.gov/totalenergy/data/browser/xls.cfm?tbl=T07.02B&freq=m.*

[32] Based on Table 6.3 (New Utility Scale Generating Units by Operating Company, Plant, Month, and Year) of the U.S. Energy Information Administration (EIA) Electric Power Monthly, data for December 2013, for the following renewable energy sources: Solar, wind, hydro, geothermal, landfill gas, and biomass. Available at: *http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_03.*

modified and reconstructed sources).[33] As a preliminary step to regulation, the EPA must list categories of stationary sources that the Administrator, in his or her judgment, finds ''cause[ ], or contribute[ ] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' The EPA has listed and regulated more than 60 stationary source categories under CAA section 111.[34]

Once the EPA has listed a source category, the EPA proposes and then promulgates ''standards of performance'' for ''new sources'' in the category.[35] A ''new source'' is ''any stationary source, the construction or modification of which is commenced after,'' in general, the date of the proposal.[36] A modification is ''any physical change . . . or change in the method of operation . . . which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.'' [37] The EPA, through regulations, has determined that certain types of changes are exempt from consideration as a modification.[38]

The EPA's 1975 framework regulations also provide that an existing source is considered a new source if it undertakes a ''reconstruction,'' which is the replacement of components of an existing facility to an extent that (1) 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 (2) it is technologically and economically feasible to meet the applicable standards.[39]

CAA section 111(a)(1) defines a ''standard of performance'' as a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This definition makes clear that the standard of performance must be based on ''the best system of emission reduction . . . adequately demonstrated'' (BSER). The standard that the EPA develops, based on the BSER, is commonly a numeric emission limit, expressed as a performance level (e.g., a rate-based standard). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance. Rather, sources generally may select any measure or combination of measures that will achieve the emissions level of the standard.[40] In establishing standards of performance, the EPA has significant discretion to create subcategories based on source type, class or size.[41]

When the EPA establishes NSPS for new sources in a particular source category, the EPA is also required, under CAA section 111(d)(1), to establish requirements for existing sources in that source category for any air pollutant that, in general, is not regulated under the CAA section 109 requirements for the National Ambient Air Quality Standards or regulated under the CAA section 112 requirements for hazardous air pollutants. Unlike CAA section 111(b), which gives EPA direct authority to set national standards, CAA section 111(d) requires the EPA to promulgate emission guidelines directing states to develop and submit, for EPA approval, state plans that include standards of performance for the existing sources.

E. Regulatory Background

In 1971, the EPA initially included fossil fuel-fired (which includes natural gas, petroleum and coal) EGUs that use steam-generating boilers in a category that it listed under CAA section 111(b)(1)(A),[42] and the EPA promulgated the first set of standards of performance for sources in that category, which it codified in subpart D.[43] In 1977, the EPA initially included fossil fuel-fired combustion turbines in a category that the EPA listed under CAA section 111(b)(1)(A),[44] and the EPA promulgated standards of performance for that source category in 1979, which the EPA codified in subpart GG.[45]

The EPA has revised those regulations, and in some instances, has revised the codifications (that is, the 40 CFR part 60 subparts), several times over the ensuing decades. In 1979, the EPA divided subpart D into 3 subparts—Da (''Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978''), Db (''Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units'') and Dc (''Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units'')—in order to codify separate requirements that it established for these subcategories.[46] In 2006, the EPA created subpart KKKK, ''Standards of Performance for Stationary Combustion Turbines,'' which applied to certain sources previously regulated in subparts Da and GG.[47] None of these subsequent rulemakings, including the revised codifications, however, constituted a new listing under CAA section 111(b)(1)(A).

The EPA promulgated amendments to subpart Da in 2006, which included new standards of performance for criteria pollutants for EGUs, but no standards of performance for GHG emissions.[48] Petitioners sought judicial review of the rule by the DC Circuit, contending, among other issues, that the rule was required to include standards of performance for GHG emissions from EGUs.[49] The January 8, 2014 preamble to the proposed CO_2 standards for new EGUs [50] includes a discussion of the GHG-related litigation of the 2006 Final Rule as well as other GHG-associated litigation.

F. Stakeholder Outreach

The EPA has engaged extensively with a broad range of stakeholders and the general public regarding climate change, carbon pollution from power plants, and carbon pollution reduction opportunities. These stakeholders included industry and electric utility representatives, state and local officials, tribal officials, labor unions and non-governmental organizations.

In February and March 2011, early in the process of developing carbon pollution standards for new power plants, the EPA held five listening sessions to obtain information and input from key stakeholders and the public.

[33] CAA section 111(b)(1)(A).

[34] *See generally* 40 CFR part 60, subparts D–MMMM.

[35] CAA section 111(b)(1)(B).

[36] CAA section 111(a)(2).

[37] CAA section 111(a)(4).

[38] 40 CFR 60.2, 60.14(e).

[39] 40 CFR 60.15.

[40] CAA section 111(b)(5).

[41] CAA section 111(b)(2).

[42] 36 FR 5931 (March 31, 1971)

[43] ''Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971,'' 36 FR 24875 (December 23, 1971) codified at 40 CFR 60.40–46.

[44] 42 FR 53657 (October 3, 1977).

[45] ''Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978,'' 44 FR 33580 (June 11, 1979).

[46] 44 FR 33580 (June 11, 1979).

[47] 71 FR 38497 (July 6, 2006), as amended at 74 FR 11861 (March 20, 2009).

[48] ''Standards of Performance for Electric Utility Steam Generating Units, Industrial-Commercial-Institutional Steam Generating Units, and Small Industrial-Commercial-Institutional Steam Generating Units, Final Rule.'' 71 FR 9866 (February 27, 2006).

[49] *State of New York, et al.* v. *EPA, No. 06–1322.*

[50] 79 FR 1430.

Each of the five sessions had a particular target audience: The electric power industry, environmental and environmental justice organizations, states and tribes, coalition groups, and the petroleum refinery industry.

The EPA has conducted subsequent outreach sessions: The vast majority of which occurred between September 2013 and November 2013. The agency held 11 public listening sessions; one national listening session in Washington, DC and 10 listening sessions in locations across the country. In addition to the 11 public listening sessions, the EPA has held hundreds of meetings with individual stakeholder groups, and meetings that brought together a variety of stakeholders to discuss a wide range of issues related to the electricity sector and regulation of GHGs under the CAA. The agency provided and encouraged multiple opportunities to engage with each one of the 50 states. The agency met with electric utility associations and electricity grid operators. Agency officials have engaged with labor unions and with leaders representing large and small industries. Because of the focus of the standard on the electricity sector, many of the EPA's meetings with industry have been with utilities and industry representatives directly related to the electricity sector. The agency has also met with energy industries such as coal and natural gas interests. In addition, the agency has met with companies that offer new technology to prevent or reduce carbon pollution, including companies that represent renewable energy and energy efficiency interests. The EPA has also met with representatives of energy intensive industries, such as the iron and steel and aluminum industries, to help understand the issues related to large industrial purchasers of electricity. Agency officials engaged with representatives of environmental justice organizations, environmental groups, and religious organizations.

Although this stakeholder outreach was primarily framed around the GHG emission guidelines for existing EGUs, the outreach encompassed issues relevant to this proposed rulemaking for modified and reconstructed EGUs. For example, existing EGUs would be subject to standards for modified and reconstructed EGUs should they undertake modification or reconstruction actions, and, thus it is important that we understand previous state and stakeholder experience with reducing CO_2 emissions in the power sector.

A detailed discussion of this stakeholder outreach is included in the preamble to the GHG emission guidelines for existing affected EGUs being proposed in a separate action today.

G. Modifications and Reconstructions

1. Modifications

The EPA's current regulations [51] define an NSPS ''modification'' as a physical or operational change that increases the source's maximum achievable hourly rate of emissions, with certain exemptions.[52]

Based on current information, the EPA believes that projects may involve equipment changes to improve efficiency that could have the effect of increasing a source's maximum achievable hourly emission rate (lb CO_2/h), even while decreasing its actual output based emission rate (lb CO_2/MWh). However, based on current information, the most likely projects that could increase the maximum achievable hourly rate of CO_2 emissions would involve the installation of add-on control equipment required to meet CAA requirements for criteria and hazardous air pollutants. These increases in CO_2 emissions would generally be small and would occur as a chemical by-product of the operation of the control equipment. All of these actions, however, would be exempted from the definition of modification under the current NSPS regulations.[53]

There are, however, some actions that could potentially trigger the modification provisions of CAA section 111(b). For example, in some cases, generation from a fossil fuel-fired electric utility steam generating unit is limited not by the size of the boiler, but by other factors, such as the size of the steam turbine or limitations in the particulate control equipment that, in turn, limit the amount of coal that can be combusted. If the steam turbine or particulate control device is upgraded, more coal can be combusted in the boiler, increasing hourly emissions.

Our base of knowledge concerning the types of NSPS modifications has depended largely on self-reporting by power plants and on the enforcement actions brought against power plants. Over the lengthy history of the NSPS program, the number of modifications that we are aware of is limited.

2. Comments on the April 2012 Proposal for New Sources Related to Modifications

In the April 13, 2012 proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (77 FR 22392),[54] the EPA did not propose standards of performance for modified sources; however, it did specifically request comment on the types of modifications that may be expected and on the appropriate control measures that may be applied. The agency received a number of comments addressing standards for modified and reconstructed EGUs.[55] The EPA subsequently withdrew that proposed rulemaking.[56] While many of those comments informed today's proposal, the EPA is not responding to those comments in this rulemaking, and if members of the public wish to express views on this rulemaking they must do so in comments on this rulemaking.

Many of those comments emphasized that a standard of performance that is based on carbon capture and storage (CCS) (or partial CCS) is not appropriate for modified EGUs. Some commenters suggested that a well-designed CAA section 111(d) program could obviate the need to set separate standards of performance for modified sources. Several commenters disagreed with EPA's assertion that it lacked adequate information to propose standards for modified sources (at that time), stating that proposed standards should be based on energy efficiency measures.

3. Reconstructions

The EPA's framework regulations, interpreting the definition of ''new source'' in CAA section 111(a)(2), provide that an existing source, ''upon reconstruction,'' becomes subject to the standard of performance for new sources.[57] The regulations define reconstruction as the replacement of components of an existing facility to such an extent that (1) 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 (2) it is technologically and economically feasible to meet the applicable standards set forth in this part.

[51] The discussion of the EPA's regulations in this rulemaking is for background purposes only. The EPA is not re-opening, and thus is not soliciting comment on, any provision in its existing regulations.

[52] 40 CFR 60.2, 60.14.

[53] 40 CFR 60.14.

[54] The proposal was subsequently withdrawn with the publication of the January 8, 2014 proposal.

[55] The comments are available in the rulemaking docket. Docket ID: EPA–HQ–OAR–2011–0660.

[56] 79 FR 1352.

[57] 40 CFR 60.15(a).

Thus, a reconstruction occurs if the existing source replaces components to such an extent that the capital costs of the new components exceed 50 percent of the capital costs of an entirely new facility, even if the existing source does not increase its emissions. In addition, the component replacement constitutes a reconstruction only if it is technologically and economically feasible for the source to meet the applicable standards. The purpose of the reconstruction provision is to avoid creating any regulatory incentive to perpetuate the operation of a facility, instead of replacing it at the end of its useful life with a newly constructed affected facility.

The regulations require the owner or operator of an existing source that proposes to replace components to an extent that exceeds the 50 percent level to notify the EPA and provide specified information. This information must include: The name and address of the owner or operator; the location of the existing facility; a brief description of the existing facility and the components which are to be replaced; a description of existing and proposed air pollution control equipment; an estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility; the estimated life of the existing facility after the replacements; and, a discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements. The regulations require the EPA to determine, within a specified time period, whether the proposed replacement constitutes a reconstruction.[58] The determination shall be based on: The fixed capital cost in comparison to the cost to construct a comparable entirely new facility; the estimated life of the facility after the replacements compared to the life of a comparable entirely new facility; the extent to which the components being replaced cause or contribute to emissions from the facility; and any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

Historically, few EGUs have undertaken reconstructions. Because of the relative prices of coal and natural gas, and the relative costs of reconstructing an existing coal-fired EGU and constructing an entirely new NGCC unit, the EPA expects that few existing coal-fired EGUs will undertake projects that will qualify the unit to be a reconstructed source during the analysis period of this rulemaking (i.e., through 2025). The EPA also does not expect existing NGCC units to undertake reconstructions during the analysis period (i.e., through 2025) because most of them are relatively young (over 80 percent of the NGCC fleet came on-line after 2000).

While there are specific provisions in the EPA's implementing regulations at 40 CFR 60.15 on what constitutes a reconstructed source (as just described), there is not such guidance on when an existing source replaces components to such a degree that it goes beyond a reconstruction and becomes essentially a newly constructed source. Historically there has been little need to distinguish between reconstructed sources and newly constructed sources as the standards of performance are typically the same for either. However, the standards proposed in today's action are different—for reasons we explain later—and, therefore, there is a need to clearly delineate between a reconstructed source and a newly constructed source. For example, it is clear that an entirely new greenfield facility would constitute a newly constructed source. It is EPA's view that, a new unit that is built on property contiguous with an existing source—but not in the same footprint as the existing source—would also constitute a newly constructed source. And, it is EPA's view that a unit that entirely, or for all practical purposes, completely replaces an existing sources by being constructed on the replaced source's existing footprint would also constitute a newly constructed source. The EPA solicits comment on the delineation between a reconstructed source, which would be subject to standards proposed in today's action, and a newly constructed source, which would be subject to standards proposed in the January 2014 proposal (79 FR 1430), for those situations where significant equipment is being replaced (enough to exceed the reconstruction threshold) but the entire unit is not being rebuilt.

In addition, the EPA requests comment on having an upper capital cost threshold for reconstruction, such that facilities that exceed that threshold would be subject to the standard of performance for newly constructed sources. With respect to this concept, the EPA requests comment on both: (1) The idea of having an upper threshold and (2) the appropriate upper threshold. With respect to the appropriate upper threshold, EPA specifically requests comment on an upper threshold within the range of 75 to 100 percent of the cost of an entirely new and comparable facility. Finally, the EPA requests comment on whether this upper threshold should be coupled with a provision comparable to 40 CFR 60.15(b)(2) and 60.15(f)(4), such that a facility that exceeded the upper threshold would not be subject to the new construction standard if it was technologically and economically infeasible for that facility to meet the new construction standard.

4. Comments on the April 2012 Proposal for New Sources Related to Reconstructions

In the April 13, 2012 proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units (77 FR 22392), the EPA did not propose standards of performance for reconstructed sources; however, it did specifically request comment on the types of reconstructions that may be expected and on the appropriate control measures that may be applied. The agency received a number of comments addressing standards for reconstructed EGUs.[59] As noted above, the agency subsequently withdrew that proposal and is not responding to those comments in this rulemaking, so that if members of the public wish to express views on this rulemaking they must do so in comments on this rulemaking.

Many of the comments on the April 13, 2012 proposal supported a delay in proposing standards for reconstructed sources. Others did not favor the delay and suggested, instead, that reconstructed sources be subject to the same standard as newly constructed sources. One commenter expressed concern that an existing source that elected to retrofit with CCS technology (perhaps in reliance on enhanced oil recovery (EOR) markets) might trigger the requirements for a reconstruction due to the high cost of CCS technology. The commenter suggested that the EPA exclude the cost of retrofitting CCS technology in order to eliminate barriers to voluntary use of that technology. Several commenters expressed concern that a reconstruction could be essentially a new plant built on a few remaining parts of an old plant. The commenters expressed concern that such reconstructed sources would face a standard that is much less stringent than a newly constructed greenfield source.

[58] 40 CFR 60.15(d)–(e).

[59] The comments are available in the rulemaking docket. Docket ID: EPA–HQ–OAR–2011–0660.

III. Proposed Requirements for Modified and Reconstructed Sources

A. Applicability Requirements

We generally refer to fossil fuel-fired electric generating units that would be subject to an emission standard in this rulemaking as ''affected'' or ''covered'' sources, units, facilities or simply as EGUs. These sources meet both the definition of ''affected'' and ''covered'' EGUs subject to an emission standard as provided by this proposed rule, and the criteria for being considered ''modified'' and ''reconstructed'' sources as defined under the provisions of CAA section 111 and the EPA's regulations.

The EPA is proposing generally similar applicability requirements, for purposes of this rule, that the EPA proposed in the January 2014 proposal.[60] [61] This section describes those requirements.

To be considered an EGU under subpart Da, the boiler or IGCC must be: (1) Capable of combusting more than 250 MMBtu/h heat input of fossil fuel,[62] (2) constructed for the purpose of supplying more than one-third of its potential net-electric output capacity to any utility power distribution system for sale [63] (that is, to the grid), and (3) constructed for the purpose of supplying more than 25 MW net-electric output to the grid.[64] In the January 2014 proposal, we proposed to revise the third criterion to read ''more than 219,000 MWh,'' as opposed to ''25 MW,'' net-electric output to the grid. This proposed change to 219,000 MWh net sales is consistent with the EPA Acid Rain Program (ARP) definition, and we have concluded that it is functionally equivalent to the 25 MW net sales language. The 25 MW sales value has been interpreted to be the continuous sale of 25 MW of electricity on an annual basis, which is equivalent to 219,000 MWh. In the January 2014 proposal, we proposed to include two additional applicability criteria specific to applicability with the GHG standards: (1) That a facility actually sells more than one-third of its potential electric output and more than 219,000 MWh to the grid on an annual basis for boilers and IGCC facilities and on a 3-year average for combustion turbines, and (2) that the GHG standards are not applicable to facilities that combust 10 percent or less fossil fuel on a 3-year average. In this proposal, we are not proposing that any of these additional applicability criteria apply for modified or reconstructed boilers or IGCC facilities. Therefore, any modified or reconstructed boiler or IGCC facility that meets the general applicability of subpart Da would also be subject to the GHG requirements. For stationary combustion turbines, we are proposing to maintain all of these criteria, along with the additional criteria specific to stationary combustion turbines, included in the January 2014 proposal: That only stationary combustion turbines that combust over 90 percent on a 3-year rolling average basis are subject to a numerical GHG standard.

We are proposing and soliciting comment on an additional amendment, not included in the January 2014 proposal, to clarify that net-electric sales, for applicability purposes, includes electricity supplied to other facilities that produce electricity to offset auxiliary loads. Without this amendment, smaller EGUs that are co-located with larger EGUs could claim that they do not meet the rule applicability criteria because their generated power is used to offset the parasitic loads of the larger facility. We are also soliciting comment if the 10 percent fossil fuel use criteria should be based on 3 consecutive calendar years or on a 3 year rolling average basis.

Consistent with the January 2014 proposal, we are proposing several additional adjustments to the way applicability is currently determined under subpart Da for purposes of modifications and reconstructions. First, we are proposing that the definition of ''potential electric output'' be revised to include ''or the design net electric output efficiency'' as an alternative to the default one-third efficiency value (i.e., the proposed definition is ''33 percent *or the design net electric output efficiency times* the maximum design heat input capacity of the steam generating unit, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (e.g., a 35 percent efficient steam generating unit with a 100 MW (341 MMBtu/h) fossil-fuel heat input capacity would have a 310,000 MWh 12 month potential electrical output capacity)'' (emphasis added)). Next, we are proposing to add ''of the thermal host facility or facilities'' to the definition of ''net-electric output'' (i.e., the proposed definition would read ''. . . the gross electric sales to the utility power distribution system minus purchased power *of the thermal host facility or facilities on a calendar year basis''* (emphasis added).

Finally, consistent with the January 2014 proposal, to avoid circumvention of the intent of the emission standards (e.g., by having auxiliary equipment provide steam to the EGU to increase the output of the EGU and not including the CO_2 emissions in determining the emission rate) and to provide additional flexibility to the regulated community through additional compliance options, we are proposing to amend the definition of a steam generating unit to include ''plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment'' in place of the existing language ''plus any integrated combustion turbines and fuel cells.'' The proposed definition would read, ''any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (nuclear steam generators are not included) *plus any integrated equipment that provides electricity or useful thermal output to either the affected facility or auxiliary equipment''* (emphasis added). We are also proposing to add the additional language to the definition of IGCC in subpart Da (or subpart TTTT) and stationary combustion turbine in subpart KKKK (or subpart TTTT).

This action proposes to set standards only for emissions of CO_2. The pollutant we propose to regulate could also be identified as a broader suite of GHGs. However, we are not proposing to set standards for any other GHGs, such as methane (CH_4) or nitrous oxide (N_2O), because they represent less than 1 percent of total estimated GHG emissions from fossil fuel-fired electric power generating units. This is consistent with the approach that was taken in the proposed standards for newly constructed EGUs (79 FR 1430).

We are also not proposing standards for certain types of sources. These include modified and reconstructed boilers and IGCC units that were constructed for the purpose of selling one-third or less of their potential output and 219,000 MWh or less to the grid. These units are not covered under

[60] See 79 FR 1445 and 1446. Note that the statements in the January 2014 Proposal that ''existing sources undertaking modifications or reconstructions; or certain projects under development, including the proposed Wolverine EGU project in Rogers City, Michigan (and, perhaps, up to two others)'' are not subject to that rulemaking, 79 FR 1446, are not relevant for purposes of the present rulemaking concerning modifications and reconstructions.

[61] In the January 2014 proposal, the EPA solicited comment on whether certain applicability requirements were appropriate in light of the fact that they assumed that the source had an operating history. In this rulemaking, the affected sources that would be undertaking modifications or reconstructions do have an operating history. As a result, to the extent the solicitation of comment in the January 2014 just described may be read to identify concerns about those applicability requirements, those concerns do not apply to this rulemaking.

[62] E.g., 40 CFR 60.40Da(a)(1).

[63] 40 CFR 60.41Da (definition of (''Electric utility steam-generating unit'').

[64] *Id.*

subpart Da for any other pollutants but are rather covered as industrial boilers under subpart Db or stationary combustion turbines under subpart KKKK. We are also not proposing standards for two types of units that are currently covered under subpart KKKK for other pollutants at this time. The first type of units is stationary combustion turbines that were constructed for the purpose of selling or are selling one-third or less of their potential output or 219,000 MWh or less to the grid. These units only account for a small amount of the CO_2 emissions from fossil fuel-fired EGUs. The second type of units is modified or reconstructed non-natural gas-fired stationary combustion turbines.[65] Under the proposed approach, applicability with the NSPS for stationary combustion turbines could change on an annual basis depending on electric sales and for facilities burning fuels other than natural gas (e.g., burning backup oil).

B. Emission Standards

In this rulemaking, the EPA is proposing standards of performance for CO_2 emissions from modified and reconstructed EGUs within two categories and several subcategories of affected fossil fuel-fired EGUs.

The proposed standards of performance for the utility boiler and IGCC category are in the form of net energy output-based CO_2 emission limits expressed in units of mass of CO_2 per unit of net energy output (e.g., net electrical output plus 75 percent of the useful thermal output), specifically, in lb CO_2/MWh-net. This emission limit would apply to affected sources upon the effective date of the final action. In this document, we sometimes refer to ''net energy output'' as ''net output.''

As explained earlier, the proposed standards of performance for natural gas-fired stationary combustion turbines are in the form of a gross output-based emission limit expressed in units of mass of CO_2 per unit of gross energy output, specifically, in lb CO_2/MWh-gross. We also solicit comment on whether we should use a net output-based approach.

The proposed method to calculate compliance is the same as was proposed in the January 2014 proposal. Compliance would be calculated as the sum of the emissions for all operating hours divided by the sum of the useful energy output over a rolling 12-operating-month period. In the alternative, as in the January 2014 proposal, we solicit comment on requiring calculation of compliance on an annual (calendar year) period. *See* 79 FR 1477.

We are proposing additional amendments to the definition of useful thermal output. The current definition excludes energy used to enhance the performance of the affected facility from being considered as useful thermal output. The intent of this restriction is to clarify that thermal energy that is directly used by the affected facility to create additional output (e.g., the economizer) is not counted as useful thermal output. Without this restriction, the energy could be doubled counted—once as useful thermal output and again as electric output. This could also be interpreted to exclude thermal energy used to reduce fuel moisture (e.g., coal drying) as being useful thermal output because it enhances the performance of the affected facility. However, coal-drying could be done at a separate offsite facility by an industrial boiler prior to delivery at the power plant. In that scenario, the CO_2 emissions from the industrial boiler would not be included when the coal-fired boiler determined compliance with the proposed standards even though the overall emissions to the atmosphere could be greater than for an integrated system where the thermal energy for the drying is supplied by the power plant. Therefore, we are proposing that thermal energy used for reducing fuel moisture be counted as useful thermal output. This approach would avoid potential disincentives for integrating coal drying at power plants. We are also proposing that default useful thermal output be measured relative to standard ambient temperature and pressure (25 °C and 14.5 pounds per square inch (psi)) instead of International Organization for Standardization (ISO) conditions (15 °C and 14.7 psi). In other words, at standard ambient temperature and pressure (SATP) conditions, the amount of useful thermal energy (commonly called ''enthalpy'') is considered to be zero. The rationale behind providing a relative measurement of thermal output is so that measurements are made relative to the energy content in the makeup water. We have concluded that standard ambient conditions are more representative than ISO conditions of the energy content in the makeup water. In addition, we are proposing the combined heat and power (CHP) facilities with high energy condensate return would measure the energy in the condensate when determining the useful thermal output. In addition, we are soliciting comment on providing credit for useful thermal output in the range of two-thirds to 100 percent.

1. Emission Standards for Modified Utility Boilers and IGCC Units

The EPA is proposing that affected modified utility boilers and IGCC units must meet a standard of performance based on the source's best potential performance, achieved through a combination of best operating practices and equipment upgrades, as the BSER. The EPA is co-proposing two alternative standards of performance. In the first alternative, modified sources would be required to meet a unit-specific numeric emission standard that is 2 percent lower than the unit's best demonstrated annual performance during the years from 2002 to the year the modification occurs.

Based on analysis of existing data, the EPA has determined that this standard can be met through a combination of best operating practices and equipment upgrades. In an analysis to determine opportunities for heat rate improvement in the U.S. coal-fired utility power fleet, the EPA found that a total of 6 percent improvement, on average, can be achieved through two types of measures: Best operating practices that have the potential to improve heat rate, on average, by 4 percent, and equipment upgrades that have the potential to improve heat rate, on average, by an additional 2 percent.[66] The EPA also proposes that the unit-specific emission rates that would apply to affected modified utility boilers and IGCC units would be no more stringent (i.e., no lower) than 1,900 lb CO_2/MWh-net for units with a heat input rating greater than 2,000 MMBtu/h, and no more stringent (i.e., no lower) than 2,100 lb CO_2/MWh-net for units with a heat input rating of 2,000 MMBtu/h or less. These proposed constraints on the stringency of unit-specific emission rate standards are consistent with the emission rate standards proposed in today's action for reconstructed utility boilers and IGCC units—based on the EPA's review and analysis of the emissions from the best available generating technology. The EPA is soliciting comment on whether the most stringent standard for modified steam generating units should take into account the current steam cycle of the

[65] Oil-fired stationary combustion turbines, including both simple and combined cycle units, are not subject to these proposed standards. These units are typically used only in areas that do not have reliable access to pipeline natural gas (for example, in non-continental areas).

[66] Additional detail can be found in the Technical Support Document: ''GHG Abatement Measures'' (Chapter 2: Heat Rate Improvement at Existing Coal-fired EGUs), available in rulemaking docket ID: EPA–HQ–OAR–2013–0602.

facility. For example, should large subcritical steam generating units have a most stringent standard that is less stringent (i.e., greater than) 1,900 lb CO_2/MWh-net, which is based on the use of a supercritical steam cycle.

As we discuss in the Legal Memorandum [67], existing sources that are subject to requirements under an approved CAA section 111(d) plan would remain subject to those requirements after undertaking a modification or reconstruction. Therefore, we are co-proposing a second alternative—that modified sources would be required to meet a unit-specific numeric emission standard that would be dependent on the timing of the modification relative to the adoption of a CAA section 111(d) plan that covers the source. Specifically, the EPA proposes that sources that modify prior to becoming subject to a CAA section 111(d) plan would be required to meet the same standard described in the first co-proposed alternative—that is, the modified source would be required to meet a unit-specific emission limit determined by the affected source's best demonstrated historical performance (in the years from 2002 to the time of the modification) with an additional 2 percent emission reduction. Sources that modify after becoming subject to a CAA section 111(d) plan would be required to meet a unit-specific emission limit that would be determined by the CAA section 111(b) implementing authority and would be based on the source's expected performance after implementation of identified unit-specific energy efficiency improvement opportunities. We seek comment on all aspects of these co-proposals, including whether the CAA section 111(b) implementing authority would determine the unit-specific emission limit, even when the implementing authority is a state, as opposed to the EPA.

In addition, we solicit comment on alternative ways to determine the best potential performance at affected modified utility boilers and IGCC units. Specifically, we are requesting comment on whether the unit-specific numerical emission standard should be based on the single best annual emission rate (for the years 2002 to the year when the modification occurs) or the best three consecutive year average emission rate. We also solicit comment on whether there are circumstances where it would not be appropriate to require that the best historical emission rate be made 2 percent more stringent, or where some other increment of additional stringency should be required.

The EPA also seeks comment on including an additional compliance option for modified utility boilers and IGCC units. Specifically, we seek comment on including uniform emission standards that are similar to the standards proposed for reconstructed utility boilers and IGCC units. Specifically, we seek comment on a standard of 1,900 lb CO_2/MWh-net for modified supercritical sources with a heat input rating of greater than 2,000 MMBtu/h and a standard of 2,100 lb CO_2/MWh-net for all modified subcritical sources and for modified supercritical sources with a heat input rating of 2,000 MMBtu/h or less. The EPA further seeks comment on whether this option should be available only to sources that modify before becoming subject to an approved CAA section 111(d) plan or to all modified boilers and IGCC units, regardless of the timing of the modification.

The EPA further solicits comment on whether, in the case of modified utility boilers and IGCC units subject to a CAA section 111(d) plan, there are any circumstances in which the emission limit should be calculated by not including the 2 percent additional emission reduction based on equipment upgrades. This may, for example, be appropriate in cases where the state plan requires heat rate improvements which improve on the source's historical performance, or where the source has recently implemented aggressive measures to improve its operating efficiency, and as a result, the additional 2 percent improvement may be unnecessary or not reasonable.

The EPA also solicits comment on requiring modified utility boilers and IGCC units subject to a CAA section 111(d) plan to take, as their unit-specific emission rate, the lower of (1) the emission rate they are subject to under the CAA section 111(d) plan, or (2) the emission rate that is 2 percent less than the unit's best demonstrated annual performance during the years from 2002 to the year the modification occurs. Similarly, the EPA solicits comment on whether modified utility boilers and IGCC units subject to a CAA section 111(d) plan could be evaluated on a case-by-case basis to determine whether, as their CAA section 111(b) standard, they should continue to be subject to the CAA section 111(d) requirements to which they are subject. One method of doing this might be through a delegation of the EPA's CAA section 111(b) authority over that source to the state administering the applicable CAA section 111(d) plan. Under this option the modified utility boilers and IGCC units would be considered to be only ''new sources'' under 111(a)(2).

The EPA further seeks comment on whether the time period of the unit's best demonstrated performance should be limited to the years from 2002 to the time that the unit becomes subject to a CAA section 111(d) plan—rather than to the date that the modification occurs. The EPA also seeks comment on whether the time period for best historic performance should be from 2002 to the date of modification—unless the source can provide evidence of significant heat rate improvements that have already been implemented, in which case the time period would be from the year of the first heat rate improvement to the modification.

The EPA also seeks comment on whether, and under what circumstances, a modified utility boiler or IGCC unit that modifies prior to becoming subject to a CAA section 111(d) plan should also be allowed to meet a emission limit that is determined from the results of an energy assessment or audit. The EPA also requests comment on whether this approach should be limited to sources that may have voluntarily, or for any other reason, implemented energy efficiency measures in the time period between 2002 and the date of the modification and whether those sources should be required to provide evidence of those energy efficiency improvements.

The EPA also solicits comment on whether we should—as we have proposed in this action—have different standards of performance for modified utility boilers and IGCC units depending on whether a CAA section 111(d) plan has been submitted (or a federal plan promulgated). On the one hand, a CAA section 111(d) plan may not necessarily impose obligations on a particular unit. On the other hand, such a plan may impose significant obligations on a particular source, and if that source modifies, it may not be as well positioned to implement additional controls. A state, in developing a CAA section 111(d) plan, may choose to confer with its sources to determine whether any expect to modify, and, if any do, to take that into account in developing the state plan.

2. Emission Standards for Modified Natural Gas-Fired Stationary Combustion Turbines

For affected modified natural gas-fired stationary combustion turbines, this action proposes standards of performance that are based on efficient NGCC technology as the BSER. The emission limits proposed for these

[67] Legal Memorandum available in rulemaking docket ID: EPA–HQ–OAR–2013–0602.

sources are 1,000 lb CO_2/MWh-gross for facilities with heat input ratings greater than 850 MMBtu/h, and 1,100 lb CO_2/MWh-gross for facilities with heat input ratings of 850 MMBtu/h or less.[68]

In the companion rulemaking proposing emission guidelines under CAA section 111(d) for CO_2 emissions from existing affected EGUs, the EPA is proposing that an existing source that becomes subject to requirements under CAA section 111(d) will continue to be subject to those requirements even after it undertakes a modification or reconstruction. This is also discussed in greater detail in the Legal Memorandum.[69] Under this interpretation, a modified or reconstructed source would be subject to both (1) the CAA section 111(d) requirements that it had previously been subject to and (2) the modified source or reconstructed source standard under CAA section 111(b) proposed in this rulemaking.

The EPA also solicits comment on an optional alternative method for calculating the emission limit that would be applicable to an affected modified natural gas-fired stationary combustion turbine after that unit becomes subject to a CAA section 111(d) plan. The EPA specifically seeks comment on the option of allowing the affected source to meet a unit-specific emission limit that is determined by the CAA section 111(b) implementing authority from an assessment to identify energy efficiency improvement opportunities for the affected source.

3. Emission Standard for Reconstructed EGUs

Reconstructed fossil fuel-fired boilers and IGCC units with a heat input rating that is greater than 2,000 MMBtu/h would be required to meet a standard of 1,900 lb CO_2/MWh-net. Reconstructed fossil fuel-fired utility boilers and IGCC units with a heat input rating that is 2,000 MMBtu/h or less would be required to meet a standard of 2,100 lb CO_2/MWh-net.

Reconstructed natural gas-fired stationary combustion turbines with a heat input rating greater than 850 MMBtu/h would be required to meet a standard of 1,000 lb CO_2/MWh-gross. Reconstructed combustion turbines with a heat input rating of 850 MMBtu/h or less would be required to meet a standard of 1,100 lb CO_2/MWh-gross.

While the EPA is proposing these standards of performance, we are also taking comment on a range of potential emission limits. Specifically, we solicit comment on the following emission limit ranges:

(1) For reconstructed fossil fuel-fired boilers and IGCC units with a heat input rating that is greater than 2,000 MMBtu/h, a range of 1,700–2,100 lb CO_2/MWh-net;

(2) for reconstructed fossil fuel-fired boilers and IGCC units with a heat input rating of 2,000 MMBtu/h or less, a range of 1,900–2,300 lb CO_2/MWh-net;

(3) for reconstructed stationary combustion turbines with a heat input rating greater than 850 MMBtu/h, a range of 950–1,100 lb CO_2/MWh-gross; and

(4) for reconstructed stationary combustion turbines with a heat input rating of 850 MMBtu/h or less, a range of 1,000–1,200 lb CO_2/MWh-gross.

We also solicit comment on whether: (1) The standards for utility boilers and IGCC units should be subcategorized by primary fuel type, (2) the small utility boiler and IGCC unit subcategory should be limited to utility boilers so that all IGCC units would be in the large subcategory regardless of size, or if there are sufficient alternate compliance technologies (e.g., co-firing natural gas) that the small unit subcategory is unnecessary and should be eliminated so that those sources would be required to meet the same emission standard as large utility boilers and IGCC units, and (3) an annual short-term performance test should be required for stationary combustion turbines in addition to the 12-operating-month rolling average standard. Requiring an initial and annual short term compliance test that is numerically more stringent than the 12-operating-month standard for modified and reconstructed stationary combustion turbines would insure that efficient stationary combustion turbines are installed and properly maintained. The less stringent 12-month rolling average standard would be set at a level that would account for operating conditions where the emission rate is higher than design conditions.

4. Net Output

We are proposing standards for modified and reconstructed units as net output emission rates. We are also requesting comment on using either gross output standards or adjusted gross output based standards in the final rule.[70]

C. Startup, Shutdown and Malfunction Requirements

We are proposing the standards in this rule apply at all times, including during periods of startup and shutdown. This section provides a summary of the requirements.

1. Startups and Shutdowns

Consistent with *Sierra Club* v. *EPA,*[71] the EPA is proposing standards in this rule that apply at all times, including during startups and shutdowns. In proposing the standards in this rule, the EPA has taken into account startup and shutdown periods, which are included in the compliance calculation as periods of partial load. The proposed method to calculate compliance is to sum the emissions for all operating hours and to divide that value by the sum of the electric energy output and useful thermal energy output, where applicable for CHP EGUs, over a rolling 12-operating-month period. The EPA is proposing that sources incorporate in their compliance determinations emissions from all periods, including startup or shutdown, during which fuel is combusted and emissions monitors are not out of control, in addition to all power produced over the periods of emissions measurements. Given that the duration of startup or shutdown periods are expected to be small relative to the duration of periods of normal operation and that the fraction of power generated during periods of startup or shutdown is expected to be very small, the impact of these periods on the total average is expected to be minimal.

2. Malfunctions

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. However, by contrast, malfunction is defined as ''any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions'' (40 CFR 60.2). The EPA has determined that CAA section 111 does not require that emissions that occur during periods of malfunction be

[68] This subcategorization of stationary combustion turbines is consistent with the subcategories used in the combustion turbine (subpart KKKK) criteria pollutant NSPS. The size limit of 850 MMBtu/h corresponds to approximately 100 MWe.

[69] Legal Memorandum available in rulemaking docket ID: EPA–HQ–OAR–2013–0602.

[70] In the January 8, 2014 proposal for new sources, we proposed standards as gross output emission rates, *See* 79 FR 1447 and 1448. In the rulemaking for existing sources that we are proposing concurrently with this rulemaking, we are proposing emission guidelines that call for state standards as net output emission rates (but seek comment on gross output-based emission rates).

[71] 551 F.3d 1019 (D.C. Cir. 2008).

factored into development of CAA section 111 standards. Nothing in CAA section 111 or in case law requires that the EPA anticipate and account for the innumerable types of potential malfunction events in setting emission standards. CAA section 111 provides that the EPA set standards of performance which reflect the degree of emission limitation achievable through ''the application of the best system of emission reduction'' that the EPA determines is adequately demonstrated. A malfunction is a failure of the source to perform in a ''normal or usual manner'' and no statutory language compels EPA to consider such events in setting standards based on the ''best system of emission reduction.'' The ''application of the best system of emission reduction'' is more appropriately understood to include units operating in such a way as to avoid malfunctions.

Further, accounting for malfunctions in setting emission standards would be difficult, if not impossible, given the myriad different types of malfunctions that can occur across all sources in the category and given the difficulties associated with predicting or accounting for the frequency, degree, and duration of various malfunctions that might occur. As such, the performance of units that are malfunctioning is not ''reasonably'' foreseeable. *See, e.g., Sierra Club* v. *EPA,* 167 F.3d 658, 662 (D.C. Cir. 1999) (''The EPA typically has wide latitude in determining the extent of data-gathering necessary to solve a problem. We generally defer to an agency's decision to proceed on the basis of imperfect scientific information, rather than to 'invest the resources to conduct the perfect study.'''') *See also, Weyerhaeuser* v *Costle,* 590 F.2d 1011, 1058 (D.C. Cir. 1978) ('' In the nature of things, no general limit, individual permit, or even any upset provision can anticipate all upset situations. After a certain point, the transgression of regulatory limits caused by 'uncontrollable acts of third parties,' such as strikes, sabotage, operator intoxication or insanity, and a variety of other eventualities, must be a matter for the administrative exercise of case-by-case enforcement discretion, not for specification in advance by regulation.''). In addition, emissions during a malfunction event can be significantly higher than emissions at any other time of source operation and thus accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing, non-malfunctioning source. It is reasonable to interpret CAA section 111 to avoid such a result. The EPA's approach to malfunctions is consistent with CAA section 111 and is a reasonable interpretation of the statute.

In the event that a source fails to comply with the applicable CAA section 111 standards as a result of a malfunction event, the EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as undertake root cause analyses to ascertain and rectify excess emissions. The EPA would also consider whether the source's failure to comply with the CAA section 111 standard was, in fact, ''sudden, infrequent, not reasonably preventable'' and was not instead ''caused in part by poor maintenance or careless operation.'' 40 CFR 60.2 (containing the definition of malfunction).

Further, to the extent the EPA files an enforcement action against a source for violation of an emission standard, the source can raise any and all defenses in that enforcement action and at federal district court will determine what, if any, relief is appropriate. The same is true for citizen enforcement actions. Similarly, the presiding officer in an administrative proceeding can consider any defense raised and determine whether administrative penalties are appropriate.

In several prior rules, the EPA had included an affirmative defense to civil penalties for violations caused by malfunctions in an effort to create a system that incorporates some flexibility, recognizing that there is a tension, inherent in many types of air regulation, in ensuring adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission standards may be violated under circumstances entirely beyond the control of the source. Although the EPA recognized that its case-by-case enforcement discretion provides sufficient flexibility in these circumstances, it included the affirmative defense to provide a more formalized approach and more regulatory clarity. *See Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal case-by-case enforcement discretion approach is adequate); *but see Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977) (requiring a more formalized approach to consideration of ''upsets beyond the control of the permit holder''). Under the EPA's regulatory affirmative defense provisions, if a source could demonstrate in a judicial or administrative proceeding that it had met the requirements of the affirmative defense in the regulation, civil penalties would not be assessed. Recently, the U.S. Court of Appeals for the District of Columbia Circuit vacated such an affirmative defense in one of the EPA's CAA section 112(d) regulations. *NRDC* v. *EPA,* No. 10–1371, 2014 U.S. App. LEXIS 7281 (D.C. Cir. April 18, 2014) (vacating affirmative defense provisions in CAA section 112(d) rule establishing emission standards for Portland cement kilns). The court found that the EPA lacked authority to establish an affirmative defense for private civil suits and held that under the CAA, the authority to determine civil penalty amounts lies exclusively with the courts, not the EPA. Specifically, the Court found: ''As the language of the statute makes clear, the courts determine, on a case-by-case basis, whether civil penalties are 'appropriate.' '' *See also id.* at *21 (''[U]nder this statute, deciding whether penalties are 'appropriate' in a given private civil suit is a job for the courts, not EPA.'').[72] In light of *NRDC,* the EPA is not including a regulatory affirmative defense provision in this rulemaking. As explained above, if a source is unable to comply with emissions standards as a result of a malfunction, the EPA may use its case-by-case enforcement discretion to provide flexibility, as appropriate. Further, as the DC Circuit recognized, in an EPA or citizen enforcement action, the court has the discretion to consider any defense raised and determine whether penalties are appropriate. *Cf.id.* at *24. (stating that arguments that violation were caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same logic applies to EPA administrative enforcement actions.

D. Continuous Monitoring Requirements

We are proposing the same monitoring requirements for modified and reconstructed sources as were proposed for newly constructed sources in the January 2014 proposal. This section provides a summary of the requirements. For additional detail, see 79 FR 1450 and 1451.

Today's proposed rule would require owners or operators of EGUs that combust solid fuel to install, certify, maintain, and operate continuous emission monitoring systems (CEMS) to

[72] The court's reasoning in *NRDC* focuses on civil judicial actions. The court noted that ''EPA's ability to determine whether penalties should be assessed for Clean Air Act violations extends only to administrative penalties, not to civil penalties imposed by a court.'' *Id.*

measure CO_2 concentration, stack gas flow rate, and (if needed) stack gas moisture content in accordance with 40 CFR part 75, in order to determine hourly CO_2 mass emissions rates (tons/h).

The proposed rule would allow owners or operators of EGUs that burn exclusively gaseous or liquid fuels to install fuel flow meters as an alternative to CEMS and to calculate the hourly CO_2 mass emissions rates using Equation G–4 in Appendix G to part 75. To implement this option, hourly measurements of fuel flow rate and periodic determinations of the gross calorific value (GCV) of the fuel are also required, in accordance with Appendix D to part 75.

In addition to requiring monitoring of the CO_2 mass emission rate, the proposed rule would require EGU owners or operators to monitor the hourly unit operating time and ''gross output'', expressed in megawatt hours (MWh). The gross output includes electrical output plus any mechanical output, plus 75 percent of any useful thermal output.

The proposed rule would require EGU owners or operators to prepare and submit a monitoring plan that includes both electronic and hard copy components, in accordance with 40 CFR 75.53(g) and (h). Further, all monitoring systems used to determine the CO_2 mass emission rates would have to be certified according to section 75.20 and section 6 of part 75, Appendix A within the 180-day window of time allotted under section 75.4(b), and would be required to meet the applicable on-going quality assurance procedures in Appendices B and D to part 75.

The proposed rule would require only those operating hours in which valid data are collected and recorded for all of the parameters in the CO_2 mass emission rate equation to be used for compliance purposes. Additionally for EGUs using CO_2 CEMS, only unadjusted stack gas flow rate values would be used in the emissions calculations. In this proposal, part 75 bias adjustment factors (BAFs) would not be applied to the flow rate data. These restrictions on the use of Part 75 data for Part 60 compliance are consistent with previous NSPS regulations and revisions.

Certain variations from and additions to the basic Part 75 monitoring would be required and are detailed in the January 2014 proposal (*See* 79 FR 1451).

Special compliance provisions for units with common stack or multiple stack configurations, consistent with section 60.13(g), would be required and are detailed in the January 2014 proposal (see 79 FR 1451).

The proposed rule would require 95 percent of the operating hours in each compliance period (including the compliance periods for the intermediate emission limits) to be valid hours, i.e., operating hours in which quality-assured data are collected and recorded for all of the parameters used to calculate CO_2 mass emissions. EGU owners or operators would have the option to use backup monitoring systems, as provided in sections 75.10(e) and 75.20(d), to help meet this proposed data capture requirement.

We are proposing two additional amendments to the monitoring requirements. First, we are proposing that measurements of electricity output (both gross and net) be measured using 0.2 class electricity metering instrumentation and calibration procedures as specified under ANSI Standards No. C12.20. Second, we are proposing that hours with no gross generation or where the gross generation is less than the auxiliary loads be reported as zero instead of a negative value.

Steam is the most common type of useful thermal output for NSPS purposes. The amount of useful energy flowing in a steam header is measured with the following components: a flow meter (to determine the volumetric flow rate of steam in cubic meters per hour or the mass flow rate in kilograms per hour), a thermocouple or resistance temperature detector (to determine the temperature of the steam), and an electromechanical transmitter (to determine the pressure of the steam). The accuracy of the measurement of useful thermal energy calculation is the product of the accuracies of the flow, temperature, and pressure measurements. The January 2014 proposal includes requirements for the measurement of useful thermal output from CHP systems, but does not include associated specifications for quality assurance of the underlying flow, temperature, and pressure measurements. The EPA is considering and soliciting comment on requiring that manufacturers' maintenance recommendations be followed and include, at a minimum, annual inspection and calibration requirements for the flow meters, thermocouples or resistance temperature detectors (RTDs), and electromechanical transmitters used to acquire the steam flow rates and properties integral to calculation of useful thermal output.

The EPA is soliciting information on: (1) The technologies that are appropriate for continuous monitoring of useful thermal output, and (2) whether the EPA should specify the technologies to be used. For example, should technology choices be limited to ultrasonic, coriolis, averaging pitot tube with 2 differential pressure cells, or shedding vortex since they appear to be the most accurate? The EPA is also soliciting information on the costs of operating these systems, including ongoing maintenance, calibration intervals, and other quality assurance costs. Finally, with regard to the quality assurance requirements for continuous monitoring of useful thermal output, the EPA is soliciting comment on the appropriate ASTM, ANSI, or ASME standards (e.g., ASME PTC 4–2013, ASME PTC 19.5–2004 and ASME MFC–6–2013) that should be incorporated by reference into the final standards of performance. This would be an alternative to specifying technologies in order to ensure monitoring data are of sufficient quality for demonstrating compliance with the proposed efficiency standards.

E. Emissions Performance Testing Requirements

We are proposing the same emissions performance testing requirements for modified and reconstructed sources as were proposed for newly constructed sources in the January 2014 proposal. This section provides a summary of the requirements. For additional detail, see 79 FR 1451.

In accordance with section 75.64(a), the proposed rule would require an EGU owner or operator to begin reporting emissions data when monitoring system certification is completed or when the 180-day window in section 75.4(b) allotted for initial certification of the monitoring systems expires (whichever date is earlier). The initial performance test would consist of the first 12-operating-months of data, starting with the month in which emissions are first required to be reported. The initial 12-operating-month compliance period would begin with the first month of the first calendar year of EGU operation in which the facility exceeds the capacity factor applicability threshold.

The traditional 3-run performance tests (i.e., stack tests) described in section 60.8 would not be required for this rule. Following the initial compliance determination, the emission standard would be met on a 12-operating-month rolling average basis.

F. Continuous Compliance Requirements

We are proposing the same continuous compliance requirements for modified and reconstructed sources as were proposed for newly constructed sources in the January 2014 proposal.

This section provides a summary of the requirements. For additional detail, see 79 FR 1451.

Today's proposed rule specifies that compliance with the mass emissions rate limits would be determined on a 12-operating-month rolling average basis, updated after each new operating month. For each 12-operating-month compliance period, quality-assured data from the certified Part 75 monitoring systems would be used together with the gross output over that period of time to calculate the average CO_2 mass emissions rate.

The proposed rule specifies that the first operating month included in the initial 12-operating-month compliance period would be the month in which reporting of emissions data is required to begin under section 75.64(a), i.e., either the month in which monitoring system certification is completed or the month in which the 180-day window allotted to finish certification testing expires (whichever month is earlier).

We are proposing that initial compliance with the applicable emissions limit in kg/MWh be calculated by dividing the sum of the hourly CO_2 mass emissions values by the total gross output for the 12-operating-month period. Affected EGUs would continue to be subject to the standards and maintenance requirements in the CAA section 111 regulatory general provisions contained in 40 CFR part 60, subpart A.

G. Notification, Recordkeeping and Reporting Requirements

We are proposing the same notification, recordkeeping and reporting requirements for modified and reconstructed sources as were proposed for newly constructed sources in the January 2014 proposal. This section provides a summary of the requirements. For additional detail, see 79 FR 1451 and 1452.

Today's proposed rule would require an EGU owner or operator to comply with the applicable notification requirements in sections 60.7(a)(1) and (a)(3), section 60.19 and section 75.61. The proposed rule would also require the applicable recordkeeping requirements in subpart F of Part 75 to be met. For EGUs using CEMS, the data elements that would be recorded include, among others, hourly CO_2 concentration, stack gas flow rate, stack gas moisture content (if needed), unit operating time, and gross electric generation. For EGUs that exclusively combust liquid and/or gaseous fuel(s) and elect to determine CO_2 emissions using Equation G–4 in Appendix G of Part 75, the key data elements in subpart F that would be recorded include hourly fuel flow rates, fuel usage times, fuel GCV, gross electric generation.

The proposed rule would require EGU owners or operators to keep records of the calculations performed to determine the total CO_2 mass emissions and gross output for each operating month. Records would be kept of the calculations performed to determine the average CO_2 mass emission rate (kg/MWh) and the percentage of valid CO_2 mass emission rates in each compliance period. The proposed rule would also require records to be kept of calculations performed to determine site-specific carbon-based F-factors for use in Equation G–4 of Part 75, Appendix G (if applicable).

The proposed rule would require all affected EGU owners/operators to submit quarterly electronic emissions reports in accordance with subpart G of Part 75. The proposed rule would require these reports to be submitted using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. Except for a few EGUs that may be exempt from the Acid Rain Program (e.g., oil-fired units), this is not a new reporting requirement. Sources subject to the Acid Rain Program are already required to report the hourly CO_2 mass emission rates that are needed to assess compliance with today's rule.

Additionally, in the proposed rule and as part of an Agency-wide effort to streamline and facilitate the reporting of environmental data, the rule would require that quarterly electronic ''excess emissions'' reports be submitted using ECMPS, within 30 days after the end of each quarter. Reporting the percentage of valid CO_2 mass emission rates is necessary to demonstrate compliance with the requirement to obtain valid data for 95 percent of the operating hours in each compliance period. Any excess emissions that occur during the quarter would be identified.

IV. Rationale for Reliance on Rational Basis To Regulate GHG From Fossil Fuel-Fired EGUs

A. Rational Basis and Endangerment Finding

In the January 2014 proposal, the EPA proposed that, in order to regulate GHG from newly constructed fossil fuel-fired EGUs, the EPA needed a rational basis, but that CAA section 111 did not require an endangerment finding. The EPA further proposed that even if CAA section 111 did require such a finding, the EPA's rational basis would qualify as one. The EPA expects to finalize the January 2014 proposal by the time that it finalizes this proposed rulemaking for affected modified and reconstructed fossil fuel-fired EGUs, and in that event, the EPA would not be required to further address the rational basis or endangerment finding in this rulemaking.

However, because this rulemaking is a separate action from the January 2014 proposal, the EPA is making the same proposal—that the EPA has a rational basis for this rulemaking, and that no endangerment finding is required, but that if one is, the EPA's rational basis would qualify as one—which it made in the January 2014 proposal. *See* 79 FR 1452 through 1456.

B. Source Categories

This proposal addresses the same two source categories—fossil fuel-fired steam generating units (utility boilers and IGCC units) and natural gas-fired stationary combustion turbines—that were addressed by the January 2014 proposal. In the January 2014 proposal, the EPA included a proposal and co-proposal for the treatment of the two affected source categories, and for how the regulatory requirements applicable to these source categories would be codified in 40 CFR part 60. Specifically, the EPA proposed to create subcategories within each category, and to codify the regulatory requirements for each subcategory in 40 CFR part 60, subparts Da and KKKK, respectively. In addition, the EPA co-proposed to combine the two categories for purposes of regulating the CO_2 emissions, and to codify all the CO_2 regulatory requirements in a new subpart, TTTT.

As noted, the EPA expects to finalize the January 2014 proposal by the time that it finalizes this proposed rulemaking for modified and reconstructed fossil fuel-fired EGUs. It is the EPA's intent that the approach for categorization and codification will be the same in the final action for this proposal as is finalized for the January 2014 proposal. However, because this rulemaking is a separate action from the January 2014 proposal, the EPA is making the same proposal and co-proposal with regard to categories and codification for modified and reconstructed sources that it made with regard to new construction sources in the January 2014 proposal. That is, the EPA proposes to create subcategories within each category and to codify the regulatory requirements in 40 CFR part 60, subparts Da and KKKK, respectively; and in addition, the EPA co-proposes to combine the two categories for purposes of regulating CO_2 emissions, and to codify all the CO_2 regulatory requirements in a new subpart TTTT. *See* 79 FR 1452 through 1454.

V. Rationale for Applicability Requirements

The rationale for several of the proposed applicability requirements for modified and reconstructed sources is the same as that in the January 2014 proposal. This section provides a summary of the rationale for these requirements along with rationale for differences with the applicability included in the January 2014 proposal. In addition, we are soliciting comment on multiple alternative approaches to the applicability criteria.

The following four proposed applicability criteria are consistent with the January 2014 proposal. First, this proposal includes within the definition of a utility boiler, IGCC unit, and stationary combustion turbine that is subject to the proposed requirements, any integrated device that provides electricity or useful thermal output to the boiler, the stationary combustion turbine or to power auxiliary equipment. The rationale behind including integrated equipment recognizes that the integrated equipment may be a type of combustion unit that emits GHGs, and that it is important to assure that those GHG emissions are included as part of the overall GHG emissions from the affected source. Also consistent with the January 2014 proposal, we are considering including in the definition of the affected facility co-located non-emitting energy generation equipment included in the facility operating permit but that is not integrated into the operation of the affected facility.

Second, we are also proposing a different definition of potential electric output from the current definition that determines the potential electric output (in MWh on an annual basis) considering only the design heat input capacity of the facility and does not account for efficiency. It assumes a 33 percent net electric efficiency, regardless of the actual efficiency of the facility. Therefore, we are proposing a definition of potential electric output that allows the source the option of calculating its potential electric output on the basis of its actual design electric output efficiency on a net output basis, as an alternative to the default one-third value.

Third, we are proposing to apply the one-third sales criterion on a rolling 3-year basis instead of an annual basis for stationary combustion turbines for multiple reasons. First, extending the period to 3 years would ensure that the CO_2 standards apply only to intermediate and base load EGUs by allowing facilities intended to generally operate at low capacity factors (e.g. simple cycle turbines that generally sell less than one-third of their potential electric output) to avoid applicability. Second, only 0.2 percent of existing simple cycle turbines had a 3-year average capacity factor of greater than one-third between 2000 and 2012. We are soliciting comment on ways to address potential complications resulting from having different time periods for applicability and the actual emission standard. For example, a stationary combustion turbine that runs at a 60 percent capacity factor for years one and two but only a 5 percent capacity factor on year three would meet the proposed applicability requirements for all 3 years (since applicability is determined on a 3-year rolling average basis). However, the emission standard is on a 12-month rolling average basis and if the hours of operation on year three are even and spread out in each month the facility likely operated at low loads and may have difficulty achieving the proposed standard. This could be further complicated if the facility burned fuels other than natural gas during year 3 since the 90 percent natural gas applicability would still apply even though other fuels were burned during the emissions standard period.

Finally, we propose that if CHP facilities meet the general applicability criteria they should be subject to the same requirements as electric-only generators. However, one potential issue that we have identified is inequitable applicability to third-party CHP developers compared to CHP facilities owned by the facility using the thermal output from the CHP facility. We are therefore proposing to add ''of the thermal host facility or facilities'' to the definition of net-electric output for qualifying CHP facilities (i.e., the clause would read, ''the gross electric sales to the utility power distribution system minus purchased power *of the thermal host facility or facilities on a calendar year basis''* (emphasis added)). This would make applicability consistent for both facility-owned CHP and third-party-owned CHP.

The rationale for following applicability criteria is different from the January 2014 proposal. To clarify that existing boiler and IGCC facilities would continue to be included in CAA section 111(d) state programs regardless of their actual electric sales or fossil fuel use, we are deleting the criteria to be considered an EGU. These criteria include that the facility must (1) actually sell one-third of their potential electric output and 219,000 MWh on an annual basis and (2) the applicability exemption for facilities, than burn fossil fuel for 10 percent or less of the heat input during a 3-year rolling average period. The sales criteria exemption was intended to exempt low capacity factor facilities since they would have additional difficulties meeting the standards in the January 2014 proposal. However, the proposed standards for boilers and IGCC facilities in this rulemaking are less stringent and are achievable by low capacity factor facilities, so the applicability exemption would not be applicable. The low fossil use exemption was designed to exempt facilities that are capable of combusting fossil fuel, but burn primarily non fossil fuels. These facilities (e.g., wood-fired EGUs) typically are inherently less efficient than fossil fuel-fired EGUs, and we are soliciting comment on if we should subcategorize boilers and IGCC facilities where fossil fuel consists of 10 percent or less of the heat input during. In the event we establish a subcategory, should the heat input be determined on an annual or 3-year rolling period and should the standard be an alternate numerical limit or ''no emission standard.''

In the January 2014 proposal, we also solicit comment on various issues concerning, and different approaches to, the applicability requirements for steam generating units and combustion turbines.[73] For additional detail, see 79 FR 1459 through 1461. We are soliciting comment on additional approaches to address potential unintended negative environmental impacts and to address issues concerning how the general applicability of the CAA section 111(b) NSPS potentially impacts the CAA section 111(d) rulemaking, since only EGUs that would be included under the CAA section 111(b) applicability if they were newly constructed, modified or reconstructed are included in the state CAA section 111(d) goals.

In the January 2014 proposal, we proposed a dual electric sales applicability criterion for stationary combustion turbines of 219,000 MWh and 33 percent sales of potential electric output on a 3-year rolling average basis. In addition, we specifically solicited comment on a range of 20 to 40 percent sales of potential electric output. However, the dual electric sales applicability could potentially result in

[73] Requests for comment in the January 2014 proposal regarding the appropriateness of certain applicability requirements that are based on a source's operations do not apply to this proposed rulemaking. Whereas newly constructed sources would not have a history of operating, in this rulemaking, the affected sources that would be undertaking modifications or reconstructions do have an operating history.

the installation, modification or reconstruction of smaller, less efficient simple cycle combustion turbines rather than larger, more efficient simple cycle combustion turbines. For simple cycle combustion turbines that are smaller than approximately 70 MW, the 219,000 MWh sales would be the determining criteria for whether the facility is subject to an emission standard. Smaller EGUs can sell over one-third of their potential electric output and still not be subject to a GHG emission standard. This could potentially place larger, more efficient simple cycle combustion turbines at a disadvantage since they would be limited to selling less (e.g., one-third) of their potential electric output. This could result in higher GHG emissions, and we are soliciting comment on approaches to minimize this outcome. One approach we are considering is changing the ''one-third potential electric output'' sales criteria to ''the design net efficiency times the potential electric output'' for simple cycle combustion turbines. This would have the effect of allowing the most efficient larger simple cycle combustion turbines currently available to sell approximately 38 percent of their potential electric output on a 3-year rolling average before an emission standard would apply. The smallest aeroderivative stationary combustion turbine designs have efficiencies of approximately 30 percent or greater, but these combustion turbine engines are smaller in size and the 219,000 MWh sales limit would still be the controlling criterion. Lower efficiency industrial frame turbines have efficiencies of approximately 28 percent. Therefore, in this approach, applicability with an emission standard would in general increase the electric sales criteria for the larger, more efficient aeroderivative simple cycle combustion turbines and decrease it larger, less efficient industrial frame simple cycle turbines. We are soliciting comment on if this change would be sufficient to avoid the potential adverse environmental impact mentioned previously or if a multiplication factor, such as 1.1 (we are soliciting comment on an appropriate factor), should be applied to the design net efficiency to determine the percent sales applicability criterion. The percent electric sales criterion would read, for example, ''1.1 times the design net efficiency times the potential electric output'' for simple cycle combustion turbines. The result of this approach is that the most efficient simple cycle turbines would be able to sell approximately 42 percent of their potential electric output prior to becoming subject to a GHG standard. Conversely, the least efficient simple cycle turbines would be limited to selling 31 percent of their potential electric output prior to becoming subject to a GHG standard. The 42 percent sales criterion is approximately equivalent to allowing 4,000 hours of operation on a 3-year average at 90 percent load before a GHG standard would apply. We are also soliciting comment on eliminating the additional 219,000 MWh sales criterion for stationary combustion turbines so that stationary combustion turbines would be subject to a GHG emission standard once they sell the specified percentage of potential electric output to the grid. This would eliminate any incentive to install multiple smaller, less efficient stationary combustion turbines rather than fewer larger, more efficient stationary combustion turbines. This approach would recognize the environmental benefit of installing more efficient simple cycle turbines regardless of size. However, this change could also potentially cover a larger percentage of industrial combined heat and power facilities. We are therefore soliciting comment on if the 219,000 MWh electric sales criterion should only be eliminated for non-CHP stationary combustion turbines. As an alternative, we are soliciting comment on an applicability exemption, and the criteria for that exemption, for highly efficient CHP facilities.

We are also soliciting comment on whether the percent sales of potential electric output is sufficient to account for the potential increased use of simple cycle combustion turbines due to the expected increased percentage of electricity generated from renewable generation in the future. Due to the intermittent nature of some renewable technologies, such as wind and solar, the electric grid must be balanced by using some type of quick response backup generation or rapid reductions in load. The EPA is soliciting comment on the extent to which simple cycle combustion turbines will be used to support additional renewable generation. We also solicit comment on the ability, relative costs and overall GHG emissions of energy storage systems (e.g., utility battery stations or flywheels) and on demand response programs to balance demand and generation from renewable electricity generation.

In addition, some of the initial feedback we received in public comments [74] on the January 2014 proposal suggests that the emissions data that the EPA used in developing the natural gas-fired stationary combustion turbine standards do not completely account for degradation in performance over the entire life of an NGCC. Also, commenters noted that NGCC units are expected to operate differently in the future due to the increased percentage of power generated from renewable sources, such as wind and solar. In addition, initial feedback suggested that the size distinction between large and small stationary combustion turbines should be adjusted.

The EPA is soliciting comment on whether a separate standard should be established for load-following (i.e., intermediate capacity factor) NGCC EGUs. The more stringent standard would apply only during periods of high annual capacity factors and a less stringent standard would apply during periods of intermediate load (e.g., when electric sales are between 33 to 60 percent of the potential electric output). This approach addresses two potential issues with the standards in the January 2014 proposal. First, certain NGCC units are designed to be highly efficient when operated as load-following units, but these design characteristics reduce the efficiency at base load. Conversely, the NGCC units with the highest base load design efficiencies are not necessarily as efficient as NGCC designed and intended to be used as load-following EGUs. Therefore, a full-load efficiency performance test would not necessarily result in the lowest CO_2 emissions in practice. Second, NGCC units operating as load-following EGUs are inherently less efficient than NGCC units operating at base load. Establishing a standard that varies with load would assure that NGCC units that are operated as base load units are as efficient as possible and still account for inherent lower efficiencies at part-load conditions.

We are requesting comment on a full range of alternatives for low capacity factor stationary combustion turbines and/or simple cycle combustion turbines to the general applicability thresholds we proposed in the January 2014 proposal. This includes soliciting comment on whether we should: Establish a separate numerical limit for low capacity factor stationary combustion turbines and/or simple cycle combustion turbines; exempt all such units; set a higher capacity factor threshold applicable to all simple cycle turbines; establish a variable capacity

[74] All public comments on the January 2014 proposal are available in the rulemaking docket, Docket ID: EPA–HQ–OAR–2013–0495.

factor that would allow more efficient, lower emitting turbines to run and be permitted for longer periods of operation (e.g., a higher capacity factor for the most efficient turbines being progressively lowered for lower efficiency turbines); or establish a CO_2 emission limitation in the form of an annual tonnage cap based on allowable emissions from smaller, less efficient units that do not exceed the 33 percent and 219,000 MWh thresholds regardless of hours operated. The EPA is considering all these options in its treatment of simple cycle combustion turbines and solicits comments on the merits of these options or variations of them. The EPA intends—when it takes final action on this proposal and on the January 2014 proposal for newly constructed sources—to finalize the same standards and applicability criteria for newly constructed, modified and reconstructed natural gas-fired stationary combustion turbines.

Consistent with the January 2014 proposal, the EPA is proposing the size distinction between large and small combustion turbines be a base load heat input rating of the combustion turbine engine of 850 MMBtu/h. As explained in the January 2014 proposal, this distinction is consistent with the criteria pollutant NSPS for stationary combustion turbines, which was based on the largest aeroderivative turbine design available at the time. However, incremental adjustments have been made to aeroderivative designs and the base load rating of the largest aeroderivative turbines now exceeds 850 MMBtu/h. The EPA is soliciting comment on increasing the size distinction between large and small stationary combustion turbines to 900 MMBtu/h to account for larger aeroderivative designs or to 1,000 MMBtu/h to account for future incremental increases in base load ratings. Alternately, the EPA is soliciting comment on increasing the size distinction to between 1,300 to 1,800 MMBtu/h. There are currently no combined cycle combustion turbines offered with turbine engine base load rating between those sizes.

VI. Rationale for Emission Standards for Reconstructed Fossil Fuel-Fired Utility Boilers and IGCC Units

A. Overview

In this section, we explain our rationale for emission standards for reconstructed fossil fuel-fired utility boiler and IGCC units, which are based on our proposal that the most efficient generating technology is the BSER for these types of units.

CAA section 111(b)(1)(B) authorizes the EPA to promulgate ''standards of performance'' for new sources, including modified and reconstructed sources. The CAA directs that standards of performance must consist of emission limits that are based on the ''best system of emission reduction . . . adequately demonstrated,'' taking into account cost and other factors. In this manner, CAA section 111 provides that the EPA's central task is to identify the BSER.

Over a 40-year period, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit or Court) has issued a number of decisions interpreting this CAA provision, including its component elements.[75] Consistent with this case law, the EPA determines the best demonstrated system based on the following key considerations, among others:

- The system of emission reduction must be technically feasible.
- The EPA must consider the amount of emissions reductions that the system would generate.
- The costs of the system must be reasonable. The EPA may consider the costs on the source level, the industry-wide level, and, at least in the case of the power sector, on the national level in terms of the overall costs of electricity and the impact on the national economy over time.[76]
- The EPA must also consider that CAA section 111 is designed to promote the deployment, development and implementation of technology.[77] [78]

Other considerations are also important, including that the EPA must also consider energy impacts, and, as with costs, may consider them on the source level and on the nationwide structure of the power sector over time. Importantly, the EPA has discretion to weigh these various considerations, may determine that some merit greater weight than others, and may vary the weighting depending on the source category. The EPA discussed the CAA requirements and Court interpretations of the BSER at length in the January 2104 proposal, 79 FR 1462 through 1467, and incorporates by reference that discussion in this rulemaking.

It should be noted at the outset that the EPA determined that reconstructions are a type of construction, and therefore subject to CAA section 111(b), as part of the 1975 framework regulations, and the EPA is not re-opening that determination.[79] The EPA also defined reconstructions in those regulations, and the EPA is not reopening that definition in this rulemaking. These provisions have two main specifications: (1) That reconstruction occurs upon replacement of components if the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct an entirely new comparable facility, and, (2) that it is technologically and economically feasible for the facility to comply with the applicable standards of performance after the replacements. 40 CFR 60.15. These reconstruction provisions have not been amended since originally promulgated in 1975, and have been implemented for numerous source categories.

B. Identification of Best System of Emissions Reduction

The EPA evaluated seven different control technology configurations as potentially representing the BSER for reconstructed fossil fuel-fired boiler and IGCC EGUs: (1) The use of partial CCS, (2) conversion to (or co-firing with) natural gas, (3) the use of CHP, (4) hybrid power plants (5) reductions in generation associated with dispatch changes, renewable generation, and

[75] *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, (D.C. Cir. 1973); *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981); *Portland Cement Association* v. *EPA,* 665 F.3d 177 (D.C. Cir. 2011).

[76] As discussed in the January 2014 Proposal, the D.C. Circuit's case law formulates the cost consideration in various ways: The costs must not be ''exorbitant [ ]'', *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), *see Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999); ''greater than the industry could bear and survive,'' *Portland Cement Association* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975); or ''excessive'' or ''unreasonable.'' *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981). In the January 2014 Proposal, EPA stated that ''these various formulations of the cost standard . . . are synonymous,'' and, for convenience, EPA used ''reasonableness'' as the formulation. EPA takes the same approach in this proposal.

[77] See discussion of case law and legislative history in the January 2014 proposal. 79 FR 1430, 1465 (cols.1–2) (January 8, 2014).

[78] It should be noted that in one of the earliest cases, *Essex Chemical Corp.* v. *Ruckelshaus,* in 1973, the Court stated that because the standard must be ''achievable,'' the emission limits must be technically feasible, and added that ''[a]n adequately demonstrated system is one which has been shown to be reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d at 427. This case law may be read to treat technical feasibility as the measure for whether the standard of performance is ''achievable,'' not as a criteria for whether the system of emission reduction is the ''best system of emission reduction . . . adequately demonstrated.'' However, for convenience, we may refer to technical feasibility as another of the criteria for the BSER.

[79] 40 FR 58417–58418, December 16, 1975 (final NSPS modification, notification, and reconstruction provisions).

demand side energy efficiency,(6) efficiency improvements achieved through the use of the most efficient generation technology, and (7) efficiency improvements achieved through a combination of best operating practices and equipment upgrades.[80]

We discuss each of these alternatives below, and explain why we propose that for reconstructed fossil fuel-fired boiler and IGCC EGUs the most efficient generating technology qualifies as the BSER.

1. Partial CCS

We considered the implementation of partial CCS as the BSER at affected reconstructed utility boilers and IGCC units. In the January 2014 proposal (79 FR 1430), the EPA found that, for new units, partial CCS has been adequately demonstrated and is technically feasible; it can be implemented at costs that are not unreasonable; it provides meaningful emission reductions; its implementation will serve to promote further development and deployment of the technology; and it would not have a significant impact on nationwide energy prices. The EPA also noted in the January 2014 proposal that most of the relatively few new projects that are in the development phase are already planning to implement CCS, so that partial CCS was consistent with current industry trends.

Partial CCS has been demonstrated at some existing EGUs. It has been demonstrated at a large pilot scale (e.g., 20 MW or greater) at two facilities: At Southern Company's Plant Barry and at AEP's Mountaineer Power Plant. A full scale, 110 MW project is currently being retrofitted at SaskPower's Boundary Dam coal-fired EGU in Canada and is expected to begin operation in 2014. Another large scale retrofit project (240 MW) is in advanced stages of project development at NRG Energy's WA Parish facility. There are also a number of smaller examples of CCS retrofits on coal-fired power plants.[81]

However, the EPA does not, at present, have sufficient information about costs to propose that partial CCS is the BSER for reconstructed utility boilers and IGCC units. Utility boilers are numerous and diverse in size and configuration, and the EPA does not have sufficient information about the range of specific configurations that would be necessary to estimate the cost of partial CCS, on either a source-specific basis or an industry-wide basis. In particular, retrofitting a plant with partial CCS would entail integrating the carbon capture equipment with the affected unit's steam cycle (or with an external source of steam or heat) in order to release the captured CO_2 and regenerate the solvent or sorbent. The cost of a retrofit would depend on many site-specific details, including the space available for the capture equipment, and the EPA lacks information on such details for a significant portion of the industry.

Therefore, the EPA does not propose to find that partial CCS is the BSER for CO_2 emissions from reconstructed fossil fuel-fired utility boilers and IGCC units.

2. Conversion to or Co-Firing With Natural Gas

While conversion to or co-firing with natural gas in a utility boiler is a technically feasible option to reduce CO_2 emission rates, it is an inefficient way to generate electricity compared to use of an NGCC and the resultant CO_2 reductions are relatively expensive. The EPA found costs for natural gas co-firing to range from approximately $83/ton to $150/ton of CO_2 avoided.[82] Even for cases where the natural gas could be co-fired without any capital investment or impact on the performance of the affected facility (e.g., an existing IGCC facility that already has a sufficient natural gas supply), the costs of CO_2 reduction would still be approximately $75/ton of CO_2 avoided. Therefore, we are not proposing natural gas co-firing as part of the BSER for modified or reconstructed steam generating units.

However, we specifically solicit comment on whether natural gas reburning (NGR) and/or similar technologies[83] should be included as part of the BSER for reconstructed utility boilers and IGCC units. NGR is a combustion technology in which a portion of the main fuel heat input is diverted to locations above the burners, creating a secondary combustion zone called the reburn zone. In NGR, the secondary (or reburn) fuel, natural gas, is injected to produce a slightly fuel rich reburn zone. Overfire air (OFA) is added above the reburn zone to complete burnout. As flue gas passes through the reburn zone, part of the NO_X formed in the main combustion zone is reduced by hydrocarbon fragments (free radicals) and converted to molecular nitrogen (N_2). With NGR at 15 and 20 percent of the heat input to a coal-fired boiler, the CO_2 emission rate would be reduced by 6 percent and 8 percent, respectively. In addition to reducing CO_2 emissions, a potential financial benefit of NGR compared to natural gas co-firing is the generation of additional NO_X reductions. These reductions could reduce costs a source is currently paying for compliance with NO_X requirements, including operations and maintenance costs associated with existing controls such as selective catalytic reduction systems and/or the cost of emission allowances under certain pollution control programs.

The EPA also requests comment on whether there are other factors or technologies related to co-firing that reduce its cost, and whether for these or other reasons, co-firing should be considered as BSER for reconstructed fossil fuel-fired electric utility steam generating units.

3. CHP

CHP, also known as cogeneration, is the simultaneous production of electricity and/or mechanical energy and useful thermal output from a single fuel. CHP requires less fuel to produce a given energy output, and because less fuel is burned to produce each unit of energy output, CHP reduces air pollution and greenhouse gas emissions. CHP has lower emission rates and can be more economic than separate electric and thermal generation. However, not all potentially modified and reconstructed utility boilers and IGCC units are located close enough to thermal hosts to economically or efficiently use the recovered thermal energy. Therefore, we are not proposing to find that CHP is the BSER for reconstructed utility boilers and IGCC units or stationary combustion turbines.

4. Hybrid Power Plant

Hybrid power plants combine two or more forms of energy input into a single facility with an integrated mix of complementary generation methods. While there are multiple types of hybrid power plants, the most relevant type for this proposal is the integration of solar energy (e.g., concentrating solar thermal with or without photovoltaic generation) with a fossil fuel-fired EGU.

[80] Note that we also evaluated these seven different technology configurations as potentially representing BSER for modified utility boilers and IGCC units. The subsequent discussion of each of these is also applicable for that evaluation as well.

[81] Technical Support Document, ''Effect of EPAct05 on BSER for New Fossil Fuel-fired Boilers and IGCCs,'' available in rulemaking docket ID: EPA–HQ–OAR–2013–0495.

[82] Chapter 2, GHG Abatement Measures Technical Support Document, available in Docket EPA–HQ–OAR–2013–0602.

[83] Fuel lean gas reburning (FLGR™), also known as controlled gas injection, similar to NGR. In FLGR™, natural gas is injected above the main combustion zone at a lower temperature zone than in NGR and avoids creating a fuel-rich zone and maintains overall fuel-lean conditions. The FLGR™ technology is reported to achieve NO_X control comparable to NGR using less than 10% natural gas heat input without the requirement for OFA. At a 10 percent heat input reburn rate, the CO_2 emission rate of a coal-fired EGU would be reduced by 4 percent.

Both coal-fired and NGCC EGUs have demonstrated the technical feasibility of integrating concentrating solar thermal energy for use in boiler feed water heating, preheating makeup water, and/or producing steam for use in the steam turbine or to power the boiler feed pumps. While hybrid power plants can reduce the CO_2 emission rate by several percent compared to similar non-hybrid power plants, not all modified and reconstructed EGUs may have the space or meteorological conditions to generate enough solar thermal energy to successfully convert to a hybrid power plant. Solar thermal facilities require abundant sunshine and significant land area and the EPA does not have sufficient information about the range of specific configurations that would be necessary to estimate the cost of implementation, on either a source-specific basis or an industry-wide basis. We solicit comment on whether hybrid power plant technology is broadly applicable to modified and reconstructed EGUs and on the costs of integrating non-emitting generation.

Our understanding is that one of the benefits of hybrid fossil EGUs is decreased incremental cost of the non-emitting (e.g., solar thermal) generated electricity due to the ability to use equipment (e.g., HRSG, steam turbine, condenser, etc.) already included at the fossil fuel-fired EGU, as well as improvement of the electrical generation efficiency of the non-emitting generation. For example, solar thermal often produces steam at relatively low temperatures and pressures and the conversion efficiency of the thermal energy in the steam to electricity is relatively low. In a hybrid power plant, the lower quality steam is heated to higher temperatures and pressures in the boiler (or HRSG) prior to expansion in the steam turbine, where it produces electricity. Upgrading the relatively low grade steam produced by the solar thermal facility improves the relative conversion efficiencies of the solar thermal to electricity process. The primary incremental costs of the non-emitting solar thermal generation in a hybrid power plant is the costs of the mirrors, additional piping, and a steam turbine that is 10 to 20 percent larger than a comparable fossil only EGU to accommodate the additional steam load during sunny hours.

We specifically solicit comment on an alternate, but similar, approach for modified and reconstructed fossil fuel-fired EGUs to integrate lower emitting generation. The recovered thermal energy from natural gas-fired combustion turbines, fuel cells, or other combustion technology could be used to reheat or preheat boiler feed water (minimizing the steam that is otherwise extracted from the steam turbine), preheat makeup water and combustion air, produce steam for use in the steam turbine or to power the boiler feed pumps, or use the exhaust directly in the boiler to generate steam. In theory, this could lower generation costs as well the GHG emissions rate for a coal-fired EGU. However, at this time we do not have sufficient information on the costs or technical feasibility of this approach to include it as the BSER for reconstructed fossil fuel-fired utility boilers.

5. Reductions in Generation Associated With Dispatch Changes, Renewable Generation, and Demand Side Energy Efficiency

In the companion proposal in today's **Federal Register**, which proposes emission guidelines for existing fossil fuel-fired EGUs, the EPA considered numerous measures that can and are being implemented to improve emission rates and to limit overall CO_2 emissions from fossil fuel-fired EGUs. The EPA grouped those measures into four main categories, or ''building blocks.'' The EPA proposed that each of the building blocks represents a method of CO_2 emission reduction at existing fossil fuel-fired EGUs that, when combined with the other building blocks, represent the ''best system of emission reduction . . . adequately demonstrated'' for existing fossil-fuel-fired EGUs under a 111(d) program. The building blocks are:

1. Lowering the carbon intensity of generation at individual affected EGUs (e.g., through heat rate improvements);
2. Reducing emissions of the most carbon-intensive affected EGUs to the extent that this can be accomplished cost-effectively by shifting generation to less carbon-intensive existing NGCC units, including NGCC units that are under construction;
3. Reducing emissions of carbon-emitting EGUs to the extent that this can be accomplished cost-effectively by expanding the amount of new, lower (or no) carbon-intensity generation; and,
4. Reducing emissions of carbon-emitting EGUs to the extent that this can be accomplished cost-effectively by increasing demand-side energy efficiency.

In this rulemaking, we are, in effect, utilizing building block one—lowering the carbon intensity of generation at individual affected EGUs through heat rate improvements—as part of the BSER determination for modified units, but we are not proposing that building blocks two, three, or four are components of the BSER determination. We solicit comment on whether building blocks two, three and four would be appropriate in light of the fact that, unlike the CAA section 111(d) emission guidelines proposal, which will result in state plans that cover all existing sources, this proposal will result in a federal rule that covers only those sources that modify or reconstruct. We note that it is not possible in advance to determine which sources will do so. We solicit comment on any additional considerations that the EPA should take into account in the applicability of building blocks two, three and four in the BSER determination.

6. Efficiency Improvements Achieved Through the Use of the Most Efficient Generation Technology

We also considered whether the proposed emission limit for reconstructed fossil fuel-fired utility boilers and IGCC units should be based on the performance of the most efficient generation technology available, which we believe is a supercritical pulverized coal (SCPC) or supercritical circulating fluidized bed (CFB) boiler for large sources, and subcritical for small sources. We propose to find that these technologies meet the criteria for the BSER.[84]

a. Technical Feasibility

The use of supercritical steam conditions has been demonstrated by many facilities since the 1960s for both large and small EGUs. In fact, the world's first commercial supercritical pressure EGU was the 125 MW Philo Unit 6 that commenced operation in 1957. Currently commercially available materials capable of tolerating steam conditions of 30 megapascal (MPa) (4,350 psi) and 605 °C (1,120 °F) have been demonstrated at coal-fired EGUs. In addition, even though the majority of recently constructed coal-fired EGUs use a single steam reheat cycle, the use of a dual steam reheat cycle has been demonstrated by multiple facilities as technically feasible. For a facility to be considered reconstructed for NSPS purposes, the boiler itself would have to be substantially refurbished. As part of a reconstruction, an owner/operator would be able to replace the steam tubing and other necessary equipment to allow the use of the best demonstrated steam cycle. Therefore, this option is technically feasible.

[84] Note that the discussion of efficiency improvements in this section is limited to reconstructed utility boilers and IGCC units. We discussed efficiency improvements for modifications below.

It should be noted that this approach identifies as the BSER changes in production technology that would result in fewer emissions, and not add-on technology that would control emissions. The kraft pulp mill NSPS (40 CFR part 60, subpart BB) is an example in which different equipment design (rather than add-on control) is the BSER for a modification or reconstruction.

b. CO_2 Reductions

The U.S. Department of Energy National Energy Technology Laboratory (DOE/NETL) has estimated that a new SCPC boiler using subbituminous coal would emit 7 percent less CO_2 per MWh than a comparable subcritical boiler. Therefore, we estimate that this standard will result in reduction in emissions of at least 7 percent when compared to the expected emissions of a reconstructed EGU using subcritical steam conditions. Smaller EGUs often use relatively low steam parameters and increasing the steam parameters to the maximum subcritical steam parameters reduces the CO_2 emissions rate. The average steam pressure and temperature for small EGUs that were reported to the information collection request associated with the Mercury and Air Toxics Standards rulemaking is 11 MPa (1,630 pounds per square inch guage (psig)) and 527 °C (980 °F) and 40 percent have no steam reheat. Increasing the steam pressure to 20 MPa (2,900 psig) and 568 °C (1,054 °F) would reduce the CO_2 emission rate by 6 percent. In addition, the use of a single steam reheat cycle reduces the CO_2 emission rate by 10 percent compared to an equivalent EGU without a steam reheat cycle.

While the percent reduction in CO_2 emissions rate using efficiency improvements achieved through the use of the most efficient generation technology is less than could be achieved by a number of the other alternatives for the BSER that the EPA considered, as noted above, those other alternatives do not meet other criteria for the BSER. Efficiency improvements achieved through the use of the most efficient generation technology do achieve the greatest emission reductions of any of the remaining alternatives that the EPA is considering.

c. Costs, Structure of the Energy Sector

DOE/NETL has estimated, based on the levelized cost of electricity (LCOE), that the capital costs of a SCPC EGU are approximately 3 percent more than a comparable subcritical EGU. In fact, the reduced fuel costs are significant enough that the overall cost to generate electricity is actually lower for a SCPC EGU compared to a subcritical EGU. Therefore, the emission reductions are considered cost effective for larger EGUs.

For smaller boilers, less than approximately 200 MW, it is the understanding of the EPA that manufacturers of steam turbines do not currently offer turbines that have been thermodynamically optimized to use supercritical steam conditions. Instead, for smaller applications, they would typically adapt their larger turbines for the application. The resulting designs have a higher cost premium than larger supercritical steam turbines and do not take full advantage of the potential efficiency improvements and the benefits of using a supercritical steam cycle are reduced. Therefore, for smaller reconstructed EGUs the EPA has determined that the BSER is the use of highest available subcritical steam conditions. The maximum viable subcritical steam parameters are 21 MPa (3,000 psi) and 570 °C (1,060 °F). The EPA specifically solicits comment on the efficiency benefits and the costs of using supercritical steam conditions for smaller EGU designs. Modern materials are widely available that can tolerate the maximum subcritical steam parameters. Therefore, we anticipate the incremental cost of increasing steam parameters within subcritical conditions is low. We solicit comment on these costs.

Designating the most efficient generation technology as the BSER for reconstructed fossil fuel-fired utility boilers and IGCC units will not have significant impacts on nationwide electricity prices. The reason is that the additional costs of the use of efficient generation will, on a nationwide basis, be small because few reconstructed coal-fired projects are expected and because at least some of these reconstructions can be expected to incorporate the most efficient generation technology even in the absence of a standard.

For the same reason, designation of the most efficient generation technology as the BSER for reconstructed fossil fuel-fired utility boilers and IGCC units will not have adverse effects on the structure of the power sector, will not impact fuel diversity, and will not have adverse effects on the supply of electricity.

d. Incentive for Technological Innovation

As noted above, the case law makes clear that the EPA is to consider the effect of its selection of BSER on technological innovation or development, but that the EPA also has the authority to weigh this factor along with the other ones. When it comes to the selection of the BSER, the EPA recognizes that reconstructed sources face inherent constraints that newly constructed greenfield sources do not; as a result, reconstructed sources present different, and in some ways more limited, opportunities for technological innovation or development. In this case, identifying the most efficient generation technology as the BSER promotes the further extension of that technology throughout the industry.

While some of the other options that the EPA considered in determining the BSER for reconstructed utility boilers and IGCC units would have led to greater opportunities for technology advancement, for the reasons discussed above, those other options did not meet other criteria. While the proposed standard is based on the use of the best available steam cycle, other energy efficiency measures will likely be developed and used (improved economizers, etc.) and these technologies will be transferrable to other EGUs.

7. Efficiency Improvements Achieved Through a Combination of Best Operating Practices and Equipment Upgrades

The EPA also considered whether a combination of best operating practices and equipment upgrades would qualify as the BSER for a reconstruction. These measures are discussed in greater detail in Section VII of this preamble. A reconstruction, because it occurs only when an owner/operator spends more than 50 percent of the cost of a replacement unit, generally entails fundamental decisions about what type of unit to rebuild. For example, one reconstruction occurred following an explosion at the boiler and resulted in a rebuild of the entire unit including both the boiler and the accompanying steam turbine.

Because a reconstruction generally entails rebuilding the unit, operating practices and equipment upgrades are not applicable as BSER. Those entail smaller scale changes to the unit that may be expected to be rebuilt anyway. In addition, the emission reductions that could be achieved through best operating practices and equipment upgrades are smaller than the most efficient generation technology.

C. Determination of the Level of the Standard

Once the EPA has determined that a particular system or technology represents BSER, the EPA must establish an emission standard based on

that system or technology. To determine an achievable emission standard, we reviewed the emission rate information submitted by owners/operators of coal-fired EGUs to the EPA's Clean Air Markets Division. For reconstructed fossil fuel-fired boiler and IGCC EGUs, the EPA proposes to find that the best available steam cycle—which qualify as the BSER—supports a standard of 1,900 lb CO_2/MWh-net for large EGUs (i.e., those with heat input greater than 2,000 MMBtu/h), and 2,100 lb CO_2/MWh-net for small EGUs (i.e., those with a heat input 2,000 MMBtu/h or less). The DOE/NETL estimates that an IGCC unit emission rate is comparable to those achieved by a supercritical coal-fired EGU. Therefore, for both technologies, these levels of the standard are based on the emission performance that can be achieved by a large pulverized or CFB coal unit using supercritical steam conditions and a small unit using subcritical steam conditions.

We are also soliciting comment on whether the emission limit may be more appropriately set at a different level. Based on the rationale included in the Technical Support Document (TSD),[85] we are soliciting comment on a range of 1,700 to 2,100 lb CO_2/MWh-net for large units and 1,900 to 2,300 lb CO_2/MWh-net for small units. An emission rate of 1,700 lb CO_2/MWh-net could potentially be met by an EGU using advanced ultra-supercritical steam conditions.[86]

We are not currently considering a standard more stringent than 1,700 lb CO_2/MWh-net for large units. Available information indicates that an EGU facility could not meet a standard of 1,600 lb CO_2/MWh-net based on the use of an advanced ultra-supercritical steam cycle, and instead would be required to implement partial CCS, co-fire approximately 40 percent natural gas directly in the boiler, or integrate non emitting or lower emitting technology in the facility's design (i.e., a hybrid power plant). We are not currently considering a standard more stringent than 1,900 lb CO_2/MWh-net for small units because available information indicates that a small EGU facility could only meet a standard of 1,800 lb CO_2/MWh-net burning bituminous coal and using the best available subcritical steam cycle. Modified facilities burning other coal types would be required to implement partial CCS, co-fire approximately 10 percent natural gas directly in the boiler, or integrate non-emitting or lower emitting technology in the facility's design (i.e., a hybrid power plant).

We are not currently considering a standard less stringent than 2,100 lb CO_2/MWh-net for large units because at that level, the NSPS would not necessarily promote the use of the best available steam cycle. At an emissions rate of 2,200 lb CO_2/MWh, large EGUs would not be required to use efficient generation technologies (e.g., they could use subcritical steam conditions). We are not currently considering a standard less stringent than 2,300 lb CO_2/MWh-net for small units because at that level, the NSPS would not necessarily promote the use of the best available steam conditions because many smaller subcritical units are operating well below 2,300 lb CO_2/MWh-net.

D. Compliance Period

The EPA is proposing that sources would be required to meet the proposed standards on a 12 operating-month rolling basis. The proposed compliance period requirements and rationale are the same as in the January 2014 proposal. This section provides a summary of the rationale. For additional detail, see 79 FR 1481 and 1482.

The 12-operating-month averaging period being proposed is important because of the inherent variability in power plant GHG emissions rates. Establishing a shorter averaging period would necessitate establishing a standard to account for the conditions that result in the lowest efficiency and therefore the highest GHG emissions rate.

EGU efficiency has a significant impact on the source's GHG emission rate. EGU efficiency can vary from month to month throughout the year. For example, high ambient temperature can negatively impact the efficiency of combustion turbine engines and steam generating units. As a result, an averaging period shorter than 12 operating-months would require us to set a standard that could be achieved under these conditions. This standard could potentially be high enough that it would not be a meaningful constraint during other parts of the year. In addition, operation at low load conditions can also negatively impact efficiency. It is likely that for some short period of time an EGU will operate at an unusually low load. A short averaging period that accounts for this operation would again not produce a meaningful constraint for typical loads.

On the other hand, a 12-operating-month rolling average explicitly accounts for variable operating conditions, allows for a more protective standard and decreased compliance burden, allows EGUs to have and use a consistent basis for calculating compliance (i.e., ensuring that 12 operating months of data would be used to calculate compliance irrespective of the number of long-term outages), and simplifies compliance for state permitting authorities. The EPA proposes that it is not necessary to have a shorter averaging period for CO_2 from these sources because the effect of GHGs on climate change depends on global atmospheric concentrations which are dependent on cumulative total emissions over time, rather than hourly or daily emissions fluctuations or local pollutant concentrations. Unlike for emissions of criteria and hazardous air pollutants, we do not believe that there are measureable implications to health or environmental impacts from short-term higher CO_2 emission rates as long as the 12-month average emissions rate is maintained.

VII. Rationale for Emission Standards for Modified Fossil Fuel-Fired Utility Boilers and IGCC Units

A. Introduction

In this section we explain our rationale for proposing, as the ''best system of emission reduction . . . adequately demonstrated'' for modified fossil fuel-fired utility boiler and IGCC EGUs, a combination of best operating practices and equipment upgrades.

We include in this discussion: (1) Our rationale for rejecting other alternatives as BSER, (2) a description of efficiency improvements achieved through a combination of best operating practices and equipment upgrades and our rationale for selecting it as BSER, and (3) our rationale for co-proposed alternative standards of performance based on this BSER (including varying the standard depending upon whether the affected source would be subject to a CAA section 111(d) plan (or promulgated federal plan) for CO_2).

B. Identification of the Best System of Emission Reduction

1. Options Considered

For the same reasons explained above for reconstructed fossil fuel-fired boiler and IGCC EGUs, the EPA is not proposing the following options to be BSER for modified fossil fuel-fired utility boiler and IGCC units: (1) The use of partial CCS, (2) conversion to (or co-firing with) natural gas, (3) the use of CHP, (4) Hybrid Power Plants, and (5)

[85] ''Best System of Emissions Reduction (BSER) for Reconstructed Electric Utility Steam Generating Units (EGUs) and Integrated Gasification Combined Cycle Facilities (IGCC)'' Technical Support Document available in the rulemaking docket (EPA–HQ–OAR–2013–0603).

[86] Advanced ultra-supercritical steam conditions are 700–760 °C (1,290–1,400 °F) and 36 MPa (5,000 psi).

reductions in generation associated with dispatch changes, renewable generation, and demand side energy efficiency.

In this section, we evaluate two other options for BSER: (1) Efficiency improvements achieved through the use of the most efficient generation technology, and (2) efficiency improvements achieved through a combination of best operating practices and equipment upgrades.

2. Use of the Most Efficient Generation Technology

We considered whether the BSER for modified fossil fuel-fired utility boilers and IGCC units should be based on the performance of the most efficient generation technology available, which we believe is a supercritical [87] unit (i.e., a SCPC or supercritical CFB boiler) for large sources, and a subcritical unit for small sources. However, as was previously noted, the existing fleet of fossil fuel-fired steam-generating boilers is numerous and diverse in size and configuration (including steam parameters), and the EPA does not have sufficient information about the range of configurations that would be necessary to estimate the cost of upgrading the steam cycle (switching to higher grade of materials in the furnace, replacement of the steam drum and conversion to a once through design, etc.) and auxiliary equipment to the most efficient generating technology. For a given boiler design, steam pressures and temperatures are limited by the properties of the materials (boiler tubes, etc.) and cannot be increased without replacing those components. We do not have sufficient information on the number of components that would need to be replaced or on the costs of replacing individual components. Furthermore, we recognize that, in at least some cases, requiring a unit to meet levels achievable by a supercritical unit, when it was not originally designed to do so, could require significant modifications to both the boiler and turbine that could start to approach the replacement cost for the unit.

Unlike in the case of reconstruction explained above, it is the understanding of the EPA that modifications do not typically involve the type of boiler rebuilding that would make this an option with reasonable cost. Consequently, the EPA does not propose to find that the use of the most efficient generation technology meets the criteria for the BSER for a uniform nationwide standard of performance.

3. Best Operating Practices and Equipment Upgrades

The second option that EPA considered for modified fossil fuel-fired utility boilers and IGCC units is a combination of best operating practices and equipment upgrades. Best operating practices includes both operating the unit in the most efficient manner for a given operating condition and replacing worn components in a timely manner. Equipment upgrades involve replacing existing components with upgraded ones or a more extensive overhaul of major equipment (turbine or boiler). We propose to find that this option meets the criteria for BSER for these EGUs.

In addition, we are co-proposing two alternative standards of performance reflective of this BSER. In the first co-proposed alternative, all modified utility boilers and IGCC units will be required to meet a unit-specific emission standard. In the second co-proposed alternative, modified sources will be required to meet unit-specific emission limits that will depend on whether the affected unit undertakes the modification before it becomes subject to a CAA section 111(d) state plan (or promulgated federal plan), or after it becomes subject to such a plan. Each variation of the BSER meets the criteria, which we discuss next. We describe the variations in more detail in the section concerning the standards of performance, which follows the discussion of the criteria.

a. Technical Feasibility

A wide range of studies have been performed evaluating the opportunity to improve the heat rate (or efficiency) [88] of an existing power plant without upgrading to the most efficient generation technology available. These studies are summarized in Chapter 2 of the TSD, ''GHG Abatement Measures'' [89] which explains that, while the studies are different in the level of detail and assumptions, the results of the studies overall suggest that the U.S. coal-fired EGU existing fleet is theoretically capable of achieving heat rate improvements ranging from 9 to 15 percent.

Many of the detailed engineering studies describe a wide range of opportunities to improve heat rate including improvements to the: (1) Materials handling equipment at the plant, (2) economizer, (3) boiler control systems, (4) soot blowers, (5) air heaters, (6) steam turbine, (7) feed water heaters, (8) condenser, (9) boiler feed pumps, (10) induced draft (ID) fans, (11) emission controls, and (12) water treatment systems.

As the studies show, these types of upgrades have been made at a wide range of power plants, demonstrating their technical feasibility.

b. CO_2 Reductions

This approach would achieve reasonable reductions in CO_2 emissions from the affected modified units as those units will be required to meet an emission standard that is consistent with more efficient operation. In light of the limited opportunities for emission reductions from retrofits, these reductions are adequate.

c. Costs

The EPA reviewed the engineering studies available in the literature and selected the Sargent & Lundy 2009 study [90] as the basis for its assessment of heat rate improvement potentials from equipment and system upgrades. We focused on thirteen heat rate improvement methods discussed by Sargent & Lundy and listed in Table 2–13 of the ''GHG Abatement Measures'' TSD. We used the average of the estimated costs (in $/kW) for each method to develop the cost-ranked list of heat rate improvement methods (listed by costs from lowest to highest in the table). The first nine items in Table 2–13 contribute about 15 percent of the total average $/kW cost for all items. We believe it is reasonable to consider those nine no-cost and low-cost heat rate improvement methods as belonging in the category of what has been described above as best practices. The remaining four methods are higher cost heat rate improvement opportunities that we believe properly fall into the category discussed here as equipment or system upgrades. Using an average of the ranges of potential Btu improvements estimated by Sargent & Lundy for the

[87] Subcritical coal-fired boilers are designed and operated with a steam cycle below the critical point of water. Supercritical coal-fired boilers are designed and operated with a steam cycle above the critical point of water. Increasing the steam pressure and temperature improves the efficiency of a steam turbine converting thermal energy to electricity, which in turn leads to increased efficiency and a lower emission rate.

[88] The heat rate is a common way to measure EGU efficiency. As the efficiency of a fossil fuel-fired EGU is increased, less fuel is burned per kilowatt-hour (kWh) generated by the EGU. This results in a corresponding decrease in CO_2 and other air pollutant emissions. Heat rate is expressed as the number of British thermal units (Btu) or kilojoules (kJ) that are required to generate 1 kWh of electricity. Lower heat rates are associated with more efficient fossil fuel-fired EGUs.

[89] Chapter 2: Heat Rate Improvement at Existing Coal-fired EGUs, Available in the rulemaking docket. Docket ID: EPA–HQ–OAR–2013–0603.

[90] Coal-fired Power Plant Heat Rate Reductions, SL–009597 Final Report, January 2009. Available in the rulemaking docket and at *http://www.epa.gov/airmarkets/resource/docs/coalfired.pdf.*

four upgrade methods, equipment or system upgrades could provide a 4 percent heat rate improvement if all were applied on an EGU that has not already made those upgrades.

The 2009 Sargent & Lundy study included an estimated range of heat rate improvement, and the associated range of capital cost for each heat rate improvement method, for units ranging in size from 200 MW to 900 MW. If the methods and unit sizes are combined, as though they were all applied on a single EGU, the range of Sargent & Lundy estimated Btu reductions (412 to 1,205 Btu) resulted in associated combined capital costs in the range of $40–150/kW. The wide ranges of estimated Btu reductions and capital costs are indicative of the wide range of real differences in the many details of site specific EGU designs, fuel types, age, size, ambient conditions, current physical condition, etc. The EPA's analysis, therefore, assumed $100/kW as a representative combined heat rate improvement capital cost to achieve whatever Btu reduction is possible at an average site.

The EPA heat rate improvement analysis resulted in the following summary conclusions:

- Some degree of heat rate improvement is already economic for high heat rate—high coal cost EGUs.
- If a fleet-wide average 6 percent heat rate is technically feasible, it would also be economic on the basis of fuel savings alone, before consideration of the value of the associated CO_2 emission reductions, on a fleet-wide basis at today's coal prices if the associated average capital cost is about $75/kW or less.
- Even at a capital cost of $100/kW and an Integrated Planning Model (IPM) projected 2020 coal price of $2.62/MMBtu, the fleet-wide cost of CO_2 reduction via 6 percent heat rate improvement would be a relatively low $7.7/tonne of CO_2 avoided.

Based on this assessment, the EPA determines that the unit-specific emission limit based on historical best performance (which captures the good operating practice at the unit) coupled with an additional 2 percent reduction (which captures minimum opportunities for additional heat rate improvements from equipment and system upgrades) can be achieved at reasonable cost.

The EPA's modeling tools do not allow projection of any specific number of utility boilers and IGCC units that are expected to trigger the NSPS modification provision. As discussed below, however, the EPA believes there are likely to be few. Hence, a unit-specific standard of performance will not have significant impacts on nationwide electricity prices or on the structure of the nation's energy sector.

d. Incentive for Technological Development

As noted previously, the case law makes clear that the EPA is to consider the effect of its selection of the BSER on technological innovation or development, but that the EPA also has the authority to weigh this factor, along with the various other factors. With the selection of emissions controls, modified sources face inherent constraints that newly constructed greenfield and even reconstructed sources do not; as a result, modified sources present different, and in some ways more limited, opportunities for technological innovation or development. In this case, the proposed standards promote technological development by promoting further development and market penetration of equipment upgrades and process changes that improve plant efficiency.

C. Determination of the Level of the Standard

Once the EPA has determined that a particular system or technology represents BSER, the EPA must establish an emission standard based on that technology.

Because the existing fossil fuel-fired steam-generating boilers are numerous and diverse in size and configuration—and because the EPA has no way to predict which of those sources may modify—developing a single standard for all modified utility boilers or IGCC units is challenging. The EPA considered a sub-categorization approach, but, as is detailed in Chapter 2 of the TSD, ''GHG Abatement Measures,'' analysis of available data did not support a number of potential sub-categorization options—such as unit size, type or age—that intuitively seemed logical.

In this action, the EPA is co-proposing two alternative standards of performance for modified utility boilers and IGCC units. In the first co-proposed alternative, all modified sources would meet a unit-specific emission limit. In the second co-proposed alternative, the modified source would be required to meet a unit-specific emission limit that will depend on the timing of the modification.

For utility boilers or IGCC units undertaking modifications, the EPA is proposing that the BSER has two components: (1) That the source operates consistently with its own best demonstrated historical performance; and (2) that the source implements other available heat rate improvement measures including upgrading of some components of the unit. Specifically, for the first co-proposed alternative, a modified utility boiler or IGCC unit would be required to maintain an emission rate that equals the unit's best demonstrated annual performance during the years from 2002 to the year the modification occurs, multiplied by 98 percent (i.e., a 2 percent further reduction), but not to be more stringent than the emission limit that would be applicable to the source if it were a reconstructed source. Consistent with the heat rate improvement analysis in the CAA section 111(d) proposal, we selected 2002 to assure we captured the impacts of maintenance cycles and year to year natural variability in CO_2 emission rate performance to capture the best historical performance. We solicit comment on whether we should select a year prior to or subsequent to 2002 for purposes of determining the best historical emission rate.

As mentioned, the EPA is also co-proposing standards of performance that are dependent on the timing of the modification. Specifically, a source that modifies prior to becoming subject to a CAA section 111(d) plan would be required to meet an emission limit that is determined using the same methodology described in the first co-proposed alternative. The modified utility boiler or IGCC unit would be required to maintain an emission rate that equals the unit's best demonstrated annual performance during the years from 2002 to the year the modification occurs, multiplied by 98 percent (i.e., a 2 percent further reduction based on equipment upgrades), but not to be more stringent than the emission limit applicable to a corresponding reconstructed source. The EPA is proposing that units undertaking modifications after they become subject to a CAA section 111(d) plan would be required to meet a unit-specific emission limit that is determined by the CAA section 111(d) implementing authority from an assessment to identify energy efficiency improvement opportunities for the affected source. This standard is informed by the fact that, as we discuss in the Legal Memorandum,[91] these sources would remain subject to the requirements of the CAA section 111(d) plan even after modifying.

The EPA also solicits comment on whether the period of best historical performance should be the years from

[91] Legal Memorandum available in rulemaking docket ID: EPA–HQ–OAR–20913–0602.

2002 to the time when the unit becomes subject to the CAA section 111(d) plan, rather than to the time of the modification.

We are considering different standards applicable before and after a source becomes subject to a CAA section 111(d) plan because we are concerned that, as a result of implementation of state plans, the additional 2 percent efficiency improvement may be unachievable for a substantial number of sources that make efficiency improvements as part of a CAA section 111(d) plan. Specifically, we are concerned that where a state imposes efficiency improvements on a source, or where a source undertakes efficiency improvements to comply with the state plan, it will have already attained the maximum level of efficiency improvement that is achievable for that unit. As a result, the source would be unable to undertake additional improvements to meet the highest level of efficiency plus the additional 2 percent reduction (based on equipment upgrades) that we are considering. We recognize that in some states, CAA section 111(d) plans may require no or limited efficiency improvements on a specific unit. In such cases, we expect such a unit to be able to achieve the standard we are considering for sources that modify prior to becoming subject to a CAA section 111(d) plan. Accordingly, for such sources, we anticipate that the audit process that we are considering will result in an emission rate consistent with the highest level of efficiency plus 2 percent (based on equipment upgrades) that we are considering for sources that modify prior to becoming subject to a state plan.

For this co-proposal, the EPA is proposing that the date for determining whether a unit is subject to a CAA section 111(d) plan is the date that the plan is initially submitted to the EPA. Although a state's plan is still subject to the EPA's approval, we believe this represents a reasonable point to determine that a source is subject to a CAA section 111(d) plan, because at that point the operator would know what requirements the source would have to meet, and would have confirmation of the state's intention to submit that plan to meet the requirements of CAA section 111(d). We are also taking comment on a range of other dates including: June 30, 2016 (the original state plan submission deadline), the date that the state promulgates its rule, the date the EPA approves the rule, and January 1, 2020 (the proposed initial compliance date for state plans).

For a source modifying after a CAA section 111(d) plan becomes applicable, a unit-specific emission standard will be determined by the CAA section 111(d) implementing authority from the results of an energy efficiency audit to identify technically feasible heat rate improvement opportunities at the affected source.

An energy efficiency audit, or assessment, is an in-depth energy study identifying all energy conservation measures appropriate for a facility given its operating parameters. An energy audit is a process that involves a thorough examination of potential savings from energy efficiency improvements, pollution prevention, and productivity improvement. It leads to the reduction of emissions of pollutants through process changes and other efficiency modifications. Besides reducing operating and maintenance costs, improving energy efficiency results in decreased fuel use which results in a corresponding decrease in emissions. Such an energy assessment requirement is included in the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR part 63, subpart DDDDD).

We propose that the energy assessment would include, at a minimum, the following elements:

1. A visual inspection of the facility to identify steam leaks or other sources of reduced efficiency;
2. a review of available engineering plans and facility operation and maintenance procedures and logs; and
3. a comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

We propose that the energy assessment be conducted by energy professionals or engineers that have expertise in evaluating energy systems. We specifically request comment on: (1) Whether energy assessor certification should be required; (2) if certification were required, what the basis of the certification should be; and (3) whether there are organizations that provide certification of specialists in evaluating energy systems. We propose that the CAA section 111(d) implementing authority will determine a unit-specific emission limit based on the results of the energy efficiency audit and we also request comment on: (1) Whether the rule should require implementation of identified energy efficiency improvements; and (2) if implementation were required, what the determining factor(s) for requiring the improvements should be. Finally, we request comment on: (1) Whether an energy efficiency audit recently completed (e.g., within 3 years of the modification) that meets or is amended to meet the rule's energy audit requirements can be used to satisfy the energy efficiency audit requirement and, in such instances, whether energy assessor approval and qualification requirements should be waived; and (2) whether facilities that operate under an energy management program compatible to ISO 50001 [92] that includes the affected units can be used to satisfy the energy efficiency audit requirement.

The EPA also seeks comment on whether, and under what circumstances, the energy audit methodology—i.e., determining the emission limit from the results of the energy audit—should be an option for sources that modify before becoming subject to a CAA section 111(d) plan. In particular, the EPA seeks comment on whether the audit methodology should be an option for all units that modify, prior to becoming subject to a CAA section 111(d) plan, or if it should be an option for sources that provide evidence that significant energy efficiency improvements were implemented after 2002 but before the modification.

D. Compliance Period

The EPA is proposing that sources would be required to meet the proposed standards on a 12 operating-month rolling basis. The compliance period requirements and rationale being proposed for modified boilers and IGCC units are the same as the requirements and rationale being proposed for reconstructed utility boilers and IGCC units (see section VII.D. of this preamble), as well as the compliance period requirements and rationale in the January 2014 proposal. For additional detail, see 79 FR 1481 and 1482.

VIII. Rationale for Emission Standards for Reconstructed Natural Gas-Fired Stationary Combustion Turbines

A. Identification of the Best System of Emission Reduction

The EPA evaluated three different control technology configurations as potentially representing the ''best system of emissions reductions . . .

[92] ISO 50001 is a specification created by the International Organization for Standardization (ISO) for an energy management system. The standard specifies the requirements for establishing, implementing, maintaining and improving an energy management system, whose purpose is to enable an organization to follow a systematic approach in achieving continual improvement of energy performance, including energy efficiency, energy security, energy use and consumption.

adequately demonstrated'' for reconstructed natural gas-fired stationary combustion turbines: (1) NGCC technology with CCS, (2) NGCC technology by itself, and (3) high efficiency simple cycle aeroderivative turbines.

1. NGCC Technology With CCS

We are not proposing to find that CCS technology is the BSER for reconstructed natural gas-fired stationary combustion turbines for the same reasons we are not proposing to find that CCS technology is the BSER for steam-generating units: an owner/operator of an existing source that is undertaking reconstruction has challenges not faced when building a new NGCC unit because the existing unit may be located at a site with space constraints that would make installation of CCS problematic. We do not have sufficient information about the universe of existing sources to be able to determine the costs of CCS, in light of these space constraints.

2. NGCC Technology

For the reasons explained below, we find NGCC technology to be BSER for reconstructed natural gas-fired stationary combustion turbines.

a. Technical Feasibility

NGCC technology is widely used in the power sector today. There are hundreds of NGCCs in the U.S. and in other countries.

b. Emission Reductions

NGCC technology is the most efficient technology for natural-gas fired stationary combustion turbines. It has an emission rate that is approximately 25 percent lower than the most effective main alternative technology, which is the simple cycle combustion turbine.

c. Cost

NGCC technology is one of the lowest cost forms of baseload and intermediate load electricity generation. Even in the case of a simple cycle turbines that operates at a capacity factor of greater than one-third, the cost of replacement with a NGCC unit is likely to be cost effective based on consideration of fuel savings alone. In the proposal for newly constructed sources (79 FR 1459), we explained that at capacity factors of greater than 20 percent, the LCOE of a combined cycle unit would be less than the LCOE of a simple cycle turbine. Because the cost of adding a HRSG to a simple cycle turbine is less than the cost of building a full combined cycle unit, the same holds true with a comparison of replacing a simple cycle turbine and upgrading it to a combined cycle turbine. Furthermore, if the owner/operator of a simple cycle turbine wishes to make a modification, they could do so—without having to comply with the requirements of this proposal—by maintaining an average annual capacity factor of less than one-third. As we explained in the proposal, few simple cycle turbines operate at an annual capacity factor of greater than one-third. (79 FR 1459)

d. Incentive for Technology Innovation

We recognize that because NGCC technology is already the state of the art technology, and is widely used, for natural gas stationary combustion turbines, identifying this technology as the BSER may not provide significant incentive for technology innovation. However, we are according less weight to this factor in this case because we consider this technology to be highly efficient and because the only more stringent alternative—CCS—is one that we are not proposing to identify as BSER, for reasons discussed above.

3. High Efficiency Simple Cycle Aeroderivative Turbines

The use of high efficiency simple cycle aeroderivative turbines does not provide emission reductions when compared to the NGCC technology. According to the Annual Energy Outlook (AEO) 2013 emissions rate information, advanced simple cycle combustion turbines have a base load rating CO_2 emissions rate of 1,150 lb CO_2/MWh-gross, which is higher than the base load rating emission rates of 830 and 760 lb CO_2/MWh-gross for the conventional and advanced NGCC model facilities, respectively. In addition, simple cycle technology is more expensive than NGCC technology; and it does not further develop or promote use of the most advanced emission control technology. For these reasons, we do not find it to be the BSER for reconstructed natural gas-fired stationary combustion turbines.

B. Determination of the Standards of Performance

The proposed standards of performance for reconstructed natural gas-fired stationary combustion turbines, which are based on BSER being efficient NGCC technology, are consistent with those that were proposed for newly constructed natural gas-fired stationary combustion turbine sources, as described in the January 2014 proposal (79 FR 1430). The EPA intends—when it takes final action on this proposal and on the January 2014 proposal for newly constructed sources, respectively—to finalize the same standards for newly constructed, modified and reconstructed natural gas-fired stationary combustion turbines. The EPA solicits comment on this approach and on any reasons why these sources should not have consistent standards.

In the January 2014 proposal, the EPA indicated that it had reviewed the CO_2 emissions data from 2007 to 2011 for natural gas-fired (non-CHP) combined cycle units that commenced operation on or after January 1, 2000, and that reported complete electric generation data, including output from the steam turbine, to the EPA. A more detailed description of the emissions data analysis is included in a TSD in the docket for that rulemaking [93] and is also included in the docket for this proposal.

Consistent with the January 2014 proposal, the EPA proposes to subcategorize the turbines into the same two size-related subcategories currently in subpart KKKK for standards of performance for the combustion turbine criteria pollutants. These subcategories are based on whether the design heat input rate to the turbine engine is either 850 MMBtu/h or less, or greater than 850 MMBtu/h. We further propose to establish different standards of performance for these two subcategories.

This subcategorization has a basis in differences in several types of equipment used in the differently sized units, which affect the efficiency of the units. Because of these differences in equipment and inherent efficiencies of scale, the smaller capacity NGCC units (850 MMBtu/h and smaller) are less efficient than the larger units (larger than 850 MMBtu/h). We are proposing standards of performance of 1,000 lb CO_2/MWh-gross for the large units and 1,100 lb CO_2/MWh-gross for the small units; and we are requesting comment on a range of 950 to 1,100 lb CO_2/MWh-gross for the large turbine subcategory and 1,000 to 1,200 lb CO_2/MWh-gross for the small turbine subcategory.

IX. Rationale for Emission Standards for Modified Natural Gas-Fired Stationary Combustion Turbines

A. Identification of the Best System of Emission Reduction

We believe that the analysis above with regards to reconstructed natural gas-fired stationary combustion turbines is also applicable to modified natural gas-fired stationary combustion

[93] ''Standard of Performance for Natural Gas-Fired Combustion Turbines'' Technical Support Document, Docket ID: EPA–HQ–OAR–2013–0495.

turbines.[94] The only potential difference that the EPA has identified is consideration of cost because the actions that could trigger modification are less extensive changes at the facility. We have considered four different scenarios that could trigger the modification provisions: (1) Modification of an older (e.g., pre-2000) combined cycle unit, (2) modification of a newer (e.g., a built in 2000 or later) combined cycle unit, (3) upgrading of a simple cycle turbine to a combined cycle unit, and, (4) modification to a simple cycle turbine other than upgrading to a combined cycle unit. As described below, in each of these cases, we believe that NGCC is cost-effective.

1. Modifications to an Older (e.g., Pre-2000) Combined Cycle Unit

Because the performance of combined cycle technology has improved so significantly since 2000, we believe that upgrading to current technology is likely to be cost effective when one considers a combination of fuel savings, and performance benefits (the ability to start up the unit more quickly and operate more efficiently over a wider range of loads).

2. Modifications to a Newer Combined Cycle Unit

These modifications are likely to be made to return the unit to close to its original operating performance, would be consistent with the requirements of today's proposal, and are not likely to significantly increase the cost of the project.

3. Upgrading a Simple Cycle Turbine to a Combined Cycle Unit

These modifications would be made to upgrade the efficiency of the unit, are consistent with the requirements of today's proposal, and are not likely to significantly increase the cost of the project.

4. Modifications to a Simple Cycle Turbine Other Than Upgrading to Combined Cycle

As was noted above—and in the proposal for newly constructed sources—when operating at higher capacity factors, the use of combined cycle technology instead of simple cycle technology pays for itself in fuel savings alone.

For these reasons, we find the use of NGCC technology to be BSER for modified natural gas-fired combustion turbines.

B. Determination of the Standards of Performance

We propose that the same standards of performance described above for reconstructed natural gas-fired stationary combustion turbines are also appropriate for modified natural gas-fired stationary combustion turbines.

We are requesting comment on a range of 950 to 1,100 lb CO_2/MWh-gross (430 to 500 kg CO_2/MWh) for the large turbine subcategory and 1,000 to 1,200 lb CO_2/MWh-gross (450 to 540 kg CO_2/MWh) for the small turbine subcategory.

For sources that are subject to a CAA section 111(d) plan, the EPA is also soliciting comment on whether the sources should be allowed to elect, as an alternative to the otherwise applicable numeric standard, to meet a unit-specific emission standard, determined by the CAA 111(d) implementing authority, based on implementation of identified energy efficiency improvement opportunities applicable to the source.

X. Impacts of the Proposed Action [95]

As explained in the RIA for this proposed rule, the EPA expects few sources will trigger either the NSPS modification or reconstruction provisions that we are proposing today. Because the EPA is aware of a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative unit. Based on the analysis, which is presented in Chapter 9 of the RIA, the EPA expects that this proposed rule will result in potential CO_2 emission changes, quantified benefits, and costs for a unit that was subject to the modification provision. In this illustrative example based on a hypothetical 500 MW coal-fired unit, we estimate costs, net of fuel savings, of $0.78 million to $4.5 million (2011$) and CO_2 reductions of 133,000 to 266,000 tons in 2025. The combined climate benefits from reductions in CO_2 and health co-benefits from reductions in SO_2, NO_X, and $PM_{2.5}$ total $18 to $33 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the lowest emission reductions scenario and $35 to $65 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the highest emission reduction scenario.[96]

A. What are the air impacts?

As explained immediately above, the EPA expects few modified or reconstructed EGUs in the period of analysis. Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the impacts for a hypothetical unit that triggered the modification provision. For this illustrative example, we estimate CO_2 reductions of 133,000 to 266,000 tons in 2025. Additionally, we estimate co-reductions of SO_2, NO_X, and $PM_{2.5}$.

B. What are the energy impacts?

This proposed rule is not anticipated to have significant impacts on the supply, distribution, or use of energy. As previously stated, the EPA expects few reconstructed or modified EGUs in the period of analysis and the nationwide cost impacts to be minimal as a result.

C. What are the compliance costs?

The EPA believes this proposed rule will have minimal compliance costs associated with it, because, as previously stated, the EPA expects few modified or reconstructed EGUs in the period of analysis. Because the EPA is aware of a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative unit. Based on the analysis, which is presented in Chapter 9 of the RIA, the EPA estimates compliance costs, net of fuel savings, of $0.78 to $4.5 million (2011$) in 2025 for a hypothetical unit that triggered the modification provisions.

D. How will this proposal contribute to climate change protection?

As previously explained, the special characteristics of GHGs make it important to take action to control the largest emissions categories without delay. Unlike most traditional air pollutants, GHGs persist in the atmosphere for time periods ranging from decades to millennia, depending on the gas. Fossil fuel-fired power plants emit more GHG emissions than any other stationary source category in the U.S.

This proposed rule would limit GHG emissions from modified fossil fuel-

[94] Technical Support Document ''Standard of Performance for Natural Gas-Fired Combustion Turbines'' available in the rulemaking docket. Docket ID: EPA–HQ–OAR–2013–0603.

[95] Note that the EPA does not project any difference in the impacts between the alternative to regulate sources under subparts Da and KKKK versus regulating them under new subpart TTTT.

[96] For purposes of this summary, we present climate benefits from CO_2 that were estimated using the model average SCC at a 3 percent discount rate. We emphasize the importance and value of considering the full range of SCC values, however, which include the model average at 2.5 and 5 percent, and the 95th percentile at 3 percent. Similarly, we summarize the health co-benefits in this synopsis at a 3 percent discount rate. We provide estimates based on additional discount rates in the RIA.

fired electric utility steam generating units (utility boilers and IGCC units) to levels consistent with the unit's best potential performance. GHG emissions from reconstructed utility boilers and IGCC units would be limited to levels consistent with modern, efficient generating technology (e.g., supercritical steam cycles). While the EPA expects few units to trigger the modification or reconstruction provisions, this proposed rule would limit GHG emissions from any modified and reconstructed stationary combustion turbines to levels consistent with modern, efficient natural gas combined cycle technology. As a result, this proposed rule will contribute to the actions required to slow or reverse the accumulation of GHG concentrations in the atmosphere, which is necessary to protect against projected climate change impacts and risks.

E. What are the economic and employment impacts?

As previously stated, the EPA anticipates few units will trigger the proposed modification or reconstruction provisions. For this reason, the proposed standards will result in minimal emission reductions, costs, or quantified benefits by 2025. There are no macroeconomic or employment impacts expected as a result of these proposed standards.

F. What are the benefits of the proposed standards?

As previously stated, the EPA anticipates few units will trigger the proposed modification or reconstruction provisions. Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative unit. Based on the analysis, which is presented in Chapter 9 of the RIA, the combined climate benefits from reductions in CO_2 and health co-benefits from reductions in SO_2, NO_X, and $PM_{2.5}$ total $18 to $33 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the lowest emission reductions scenario and $35 to $65 million (2011$) at a 3 percent discount rate for emission reductions in 2025 for the highest emission reduction scenario.[97]

XI. Statutory and Executive Order Reviews

A. Executive Order 12866, Regulatory Planning and Review, and Executive Order 13563, Improving Regulation and Regulatory Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is a ''significant regulatory action'' because it ''raises novel legal or policy issues arising out of legal mandates.'' Accordingly, the EPA submitted this action to the OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to the OMB recommendations have been documented in the docket for this action. In addition, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in Chapter 9 of the Regulatory Impact Analysis for Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.

As explained in the RIA for this proposed rule, in the period of analysis (through 2025) the EPA anticipates few sources will trigger either the modification or the reconstruction provisions proposed. Because there have been a few units that have notified the EPA of NSPS modifications in the past, we have conducted an illustrative analysis of the costs and benefits for a representative unit that is included in Chapter 9 of the RIA.

B. Paperwork Reduction Act

This proposed action is not expected to impose an information collection burden under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* Burden is defined at 5 CFR 1320.3(b). As previously stated, the EPA expects few modified or reconstructed EGUs in the period of analysis. Specifically, the EPA believes it unlikely that fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines will take actions that would constitute modifications or reconstructions as defined under the EPA's NSPS regulations. Accordingly, this proposed action is not anticipated to impose any information collection burden over the 3-year period covered by this Information Collection Request (ICR). We have estimated, however, the information collection burden that would be imposed on an affected EGU if it was modified or reconstructed. The information collection requirements in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The ICR document prepared by the EPA has been assigned the EPA ICR number 2465.03.

The EPA intends to codify the standards of performance in the same way for both this proposed action and the January 2014 proposal for newly constructed sources and is proposing the same recordkeeping and reporting requirements that were included in the January 2014 proposal.[98] See 79 FR 1498 and 1499. Although not anticipated, if an EGU were to modify or reconstruct, this proposed action would impose minimal information collection burden on affected sources beyond what those sources would already be subject to under the authorities of CAA parts 75 and 98. The OMB has previously approved the information collection requirements contained in the existing part 75 and 98 regulations (40 CFR part 75 and 40 CFR part 98) under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control numbers 2060–0626 and 2060–0629, respectively. Apart from potential energy metering modifications to comply with net energy output based emission limits proposed in this action and certain reporting costs, which are mandatory for all owners/operators subject to CAA section 111 national emission standards, there would be no new information collection costs, as the information required by this proposed rule is already collected and reported by other regulatory programs. The 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.

Although, as stated above, the EPA expects few sources will trigger either the NSPS modification or reconstruction provisions that we are proposing, if an EGU were to modify or reconstruct during the 3-year period covered by this ICR, it is likely that an EGU's energy metering equipment would need to be

[97] For purposes of this summary, we present climate benefits from CO_2 that were estimated using the model average social cost of carbon (SCC) at a 3 percent discount rate. We emphasize the importance and value of considering the full range of SCC values, however, which include the model average at 2.5 percent and 5 percent, and the 95th percentile at 3 percent. Similarly, we summarize the health co-benefits in this synopsis at a 3 percent discount rate. We provide estimates based on additional discount rates in the RIA.

[98] The information collection requirements in the January 2014 proposal have been submitted for approval to the OMB under the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* The ICR document prepared by the EPA for the January 2014 proposal has been assigned the EPA ICR number 2465.02.

modified to comply with proposed net energy output based CO_2 emission limits. Specifically, the EPA estimates that it would take approximately 3 working months for a technician to retrofit existing energy metering equipment to meet the proposed net energy output requirements. In addition, after modifications are made that enable a facility to measure net energy output, each EGU's Data Acquisition System (DAS) would need to be upgraded to accommodate reporting of net energy output rate based emissions. A modified or reconstructed EGU would be required to prepare a quarterly summary report, which includes reporting of emissions and downtime, every 3 months. The reporting burden for such a unit (averaged over the first 3 years after the effective date of the standards) is estimated to be $17,217 and 205 labor hours. Estimated cost burden is based on 2013 Bureau of Labor Statistics (BLS) labor cost data. Average burden hours per response are estimated to be 47.3 hours and the average number of annual responses over the 3-year ICR period is 4.33 per year. Burden is defined at 5 CFR 1320.3(b).

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.

To comment on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, the EPA has established a public docket for this rule, which includes this ICR, under Docket ID number EPA–HQ–OAR–2013–0603. Submit any comments related to the ICR to the EPA and OMB. See **ADDRESSES** section at the beginning of this proposed rule for where to submit comments to the EPA. Send comments to OMB at the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503, Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after June 18, 2014, a comment to OMB is best assured of having its full effect if OMB receives it by July 18, 2014. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (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 or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, small entity is defined as:

(1) A small business that is defined by the SBA's regulations at 13 CFR 121.201 (for the electric power generation industry, the small business size standard is an ultimate parent entity with less than 750 employees.);

(2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and

(3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities.

The EPA expects few modified utility boilers, IGCC units, or stationary combustion turbines in the period of analysis. An NSPS modification is defined as a physical or operational change that increases the source's maximum achievable hourly rate of emissions. The EPA does not believe that there are likely to be EGUs that will take actions that would constitute modifications as defined under the EPA's NSPS regulations.

Because there have been a limited number of units that have notified the EPA of NSPS modifications in the past, the RIA for this proposed rule includes an illustrative analysis of the costs and benefits for a representative unit.

Based on the analysis, the EPA estimates that this proposed rule could result in CO_2 emission changes, quantified benefits, or costs for a hypothetical unit that triggered the modification provision. However, we do not anticipate this proposed rule would impose significant costs on those sources, including any that are owned by small entities.

In addition, the EPA expects few reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines in the period of analysis. Reconstruction occurs when a single project replaces components or equipment in an existing facility and exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility. Due to the limited data available on reconstructions, it is not possible to conduct a representative illustrative analysis of what costs and benefits might result from this proposal in the unlikely case that a unit were to reconstruct. However, based on the low number of previous reconstructions and the BSER determination based on the most efficient available generating technology, we would expect this proposal to result in no significant CO_2 emission changes, quantified benefits, or costs for NSPS reconstructions. Accordingly, there are no anticipated economic impacts as a result of the proposed standards for reconstructed EGUs.

Nevertheless, the EPA is aware that there is substantial interest in the proposed rule among small entities (municipal and rural electric cooperatives). As summarized in section II.G. of this preamble, the EPA has conducted an unprecedented amount of stakeholder outreach. As part of that outreach, agency officials participated in many meetings with individual utilities as well as meetings with electric utility associations. Specifically, the EPA Administrator, Gina McCarthy, participated in separate meetings with both the National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA). The meetings brought together leaders of the rural cooperatives and public power utilities from across the country. The Administrator discussed and exchanged information on the unique challenges, in particular the financial structure, of NRECA and APPA member utilities. A detailed discussion of the stakeholder outreach is included in the preamble to the emission guidelines for existing affected electric utility generating units being proposed in a separate action.

In addition, as described in the RFA section of the preamble to the proposed standards of performance for GHG emissions from new EGUs (79 FR 1499 and 1500), the EPA conducted outreach to representatives of small entities while formulating the provisions of the proposed standards. Although only new EGUs would be affected by those proposed standards, the outreach regarded planned actions for newly constructed, reconstructed, modified and existing sources.

While formulating the provisions of this proposed rule, the EPA considered the input provided over the course of the stakeholder outreach. We invite comments on all aspects of this proposal

and its impacts, including potential impacts on small entities.

D. Unfunded Mandates Reform Act

This proposed rule does not contain a federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any one year. As previously stated, the EPA expects few modified or reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines in the period of analysis. Accordingly, this proposed rule is not subject to the requirements of sections 202 or 205 of UMRA.

This proposed rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

In light of the interest among governmental entities, the EPA initiated consultations with governmental entities while formulating the provisions of the proposed standards for newly constructed EGUs. This outreach regarded planned actions for newly constructed, reconstructed, modified and existing sources. As described in the UMRA discussion in the preamble to the proposed standards of performance for GHG emissions from newly constructed EGUs (79 FR 1500 and 1501), the EPA consulted with the following 10 national organizations representing state and local elected officials: (1) National Governors Association; (2) National Conference of State Legislatures; (3) Council of State Governments; (4) National League of Cities; (5) U.S. Conference of Mayors; (6) National Association of Counties; (7) International City/County Management Association; (8) National Association of Towns and Townships; (9) County Executives of America; and (10) Environmental Council of States. On February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs.

While formulating the provisions of these proposed standards, the EPA also considered the input provided over the course of the extensive stakeholder outreach conducted by the EPA (see section II.G. of this preamble).

E. Executive Order 13132, Federalism

This proposed action does not have federalism implications. It would not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This proposed action would not impose substantial direct compliance costs on state or local governments, nor would it preempt state law. Thus, Executive Order 13132 does not apply to this action.

However, as described in the Federalism discussion in the preamble to the proposed standards of performance for GHG emissions from newly constructed EGUs (79 FR 1501, January 8, 2014), the EPA consulted with state and local officials in the process of developing the proposed standards for newly constructed EGUs. This outreach regarded planned actions for newly constructed, reconstructed, modified and existing sources. The EPA engaged 10 national organizations representing state and local elected officials. The UMRA discussion in the preamble to the proposed standards of performance for GHG emissions from newly constructed EGUs (79 FR 1500 and 1501) includes a description of the consultation. In addition, on February 26, 2014, the EPA re-engaged with those governmental entities to provide a pre-proposal update on the emission guidelines for existing EGUs and emission standards for modified and reconstructed EGUs. While formulating the provisions of these proposed standards, the EPA also considered the input provided over the course of the extensive stakeholder outreach conducted by the EPA (see section II.G. of this preamble). In the spirit of Executive Order 13132 and consistent with the EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comment on this proposed action from state and local officials.

F. Executive Order 13175, Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It would neither impose substantial direct compliance costs on tribal governments, nor preempt Tribal law. This proposed rule would impose requirements on owners and operators of reconstructed and modified EGUs. The EPA is aware of three coal-fired EGUs located in Indian country but is not aware of any EGUs owned or operated by tribal entities. The EPA notes that this proposal would only affect existing sources such as the three coal-fired EGUs located in Indian country, if those EGUs were to take actions constituting modifications or reconstructions as defined under the EPA's NSPS regulations. However, as previously stated the EPA expects few modified or reconstructed EGUs in the period of analysis. Thus, Executive Order 13175 does not apply to this action.

Although Executive Order 13175 does not apply to this action, the EPA conducted outreach to tribal environmental staff and offered consultation with tribal officials in developing this action. Because the EPA is aware of tribal interest in carbon pollution standards for the power sector, prior to proposal of GHG standards for newly constructed power plants, the EPA offered consultation with tribal officials early in the process of developing the proposed regulation to permit them to have meaningful and timely input into its development. The EPA's consultation regarded planned actions for newly constructed, reconstructed, modified, and existing sources. The Consultation and Coordination with Indian Tribal Governments discussion in the preamble to the proposed standards of performance for GHG emissions from newly constructed EGUs (79 FR 1501) includes a description of that consultation.

During development of this proposed regulation, consultation letters were sent to 584 tribal leaders. The letters provided information regarding the EPA's development of both the NSPS for modified and reconstructed EGUs and emission guidelines for existing EGUs and offered consultation. No tribes have requested consultation. Tribes were invited to participate in the national informational webinar held August 27, 2013, and to which tribes were invited. In addition, a consultation/outreach meeting was held on September 9, 2013, with tribal representatives from some of the 584 tribes. The EPA also met with tribal environmental staff with the National Tribal Air Association, by teleconference, on July 25, 2013, and December 19, 2013. In those teleconferences, the EPA provided background information on the GHG emission guidelines to be developed and a summary of issues being explored by the agency. Additional detail regarding this stakeholder outreach is included in the preamble to the emission guidelines for existing affected electric utility generating units being proposed in a separate action today. The EPA also held a series of listening sessions prior to proposal of GHG standards for newly constructed power plants. Tribes participated in a session on February 17, 2011, with the state

agencies, as well as in a separate session with tribes on April 20, 2011.

The EPA will also hold additional meetings with tribal environmental staff during the public comment period, to inform them of the content of this proposal, as well as offer further consultation with tribal officials where it is appropriate. We specifically solicit additional comment from tribal officials on this proposed rule.

G. Executive Order 13045, Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is based solely on technology performance.

H. Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This proposed action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. As previously stated, the EPA expects few reconstructed or modified EGUs in the period of analysis and impacts on emissions, costs or energy supply decisions for the affected electric utility industry to be minimal as a result.

I. National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA of 1995 (Public Law No. 104–113; 15 U.S.C. 272 note) directs the EPA to use VCS in their regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs the EPA to provide Congress, through annual reports to the OMB, with explanations when an agency does not use available and applicable VCS.

This proposed rulemaking involves technical standards. The EPA proposes to use the following standards in this proposed rule: ASTM D388–12 (Standard Classification of Coals by Rank), ASTM D396–13c (Standard Specification for Fuel Oils), ASTM D975–14 (Standard Specification for Diesel Fuel Oils), D3699–13b (Standard Specification for Kerosene), D6751–12 (Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels), ASTM D7467–13 (Standard Specification for Diesel Fuel Oil, Biodiesel Blend (B6 to B20)), and ANSI C12.20 (American National Standard for Electricity Meters—0.2 and 0.5 Accuracy Classes). The EPA is proposing use of Appendices A, B, D, F and G to 40 CFR part 75; these Appendices contain standards that have already been reviewed under the NTTAA.

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 action.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies and activities on minority populations and low-income populations in the U.S.

This proposed rule limits GHG emissions from modified and reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) and stationary combustion turbines by establishing national emission standards for CO_2. The EPA has determined that this proposed rule would not result in disproportionately high and adverse human health or environmental effects on minority, low-income and indigenous populations because it does not affect the level of protection provided to human health or the environment. As previously stated, the EPA expects few modified or reconstructed fossil fuel-fired electric utility steam generating units (utility boilers and IGCC units) or stationary combustion turbines in the period of analysis.

XII. Statutory Authority

The statutory authority for this action is provided by sections 111, 301, 302, and 307(d)(1)(C) of the CAA as amended (42 U.S.C. 7411, 7601, 7602, 7607(d)(1)(C)). This action is also subject to section 307(d) of the CAA (42 U.S.C. 7607(d)).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: June 2, 2014.

Gina McCarthy,

Administrator.

Proposed Rule Amendment With Changes

The Environmental Protection Agency proposed rule amending 40 CFR parts 60, 70, 71, and 98, which was published at 79 FR 1430, January 8, 2014, proposed amendments to the regulatory text of 40 CFR part 60, subparts Da and KKKK, and, as an alternative to amending subparts Da and KKKK, to create a new subpart (40 CFR part 60, subpart TTTT) to include GHG standards for newly constructed EGUs. To facilitate understanding the amendments being proposed in this proposal, we are providing a Technical Support Document in the docket for this rulemaking in track changes that shows the proposed amendments considering the amendments proposed in the January 8, 2014, **Federal Register** publication.

[FR Doc. 2014–13725 Filed 6–17–14; 8:45 am]

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FEDERAL REGISTER

Vol. 79 Wednesday,

No. 117 June 18, 2014

Part IV

The President

Proclamation 9142—Father's Day, 2014

Executive Order 13669—2014 Amendments to the Manual for Courts-Martial, United States

Executive Order 13670—Establishing an Emergency Board To Investigate Disputes Between the Southeastern Pennsylvania Transportation Authority and Certain of Its Employees Represented by Certain Labor Organizations

Federal Register
Vol. 79, No. 117
Wednesday, June 18, 2014

Presidential Documents

Title 3—

The President

Proclamation 9142 of June 13, 2014

Father's Day, 2014

By the President of the United States of America

A Proclamation

Fatherhood is among the most difficult and rewarding jobs a man can have. It demands constant attention, frequent sacrifice, and a healthy dose of patience. Even in a time when technology allows us to connect instantly with almost anyone on earth, there is no substitute for a father's presence, care, and support. On Father's Day, we show our gratitude to the men who show us how to learn, grow, and live.

With encouragement and unconditional love, fathers guide their children and help them envision brighter futures. They are teachers and coaches, friends and role models. They instill values like hard work and integrity, and teach their kids to take responsibility for themselves and those around them. This is a task for every father—whether married or single, gay or straight, natural or adoptive—and every child deserves someone who will step up and fill this role. My Administration proudly supports dads who are not only present but also involved, who meet their commitments to their sons and daughters, even if their own fathers did not.

Today, let us reflect on our fathers' essential contributions to our lives, our society, and our Nation. Let us thank the men who understand there is nothing more important than being the best fathers they can be.

NOW, THEREFORE, I, BARACK OBAMA, President of the United States of America, in accordance with a joint resolution of the Congress approved April 24, 1972, as amended (36 U.S.C. 109), do hereby proclaim June 15, 2014, as Father's Day. I direct the appropriate officials of the Government to display the flag of the United States on all Government buildings on this day, and I call upon all citizens to observe this day with appropriate programs, ceremonies, and activities.

IN WITNESS WHEREOF, I have hereunto set my hand this thirteenth day of June, in the year of our Lord two thousand fourteen, and of the Independence of the United States of America the two hundred and thirty-eighth.

[FR Doc. 2014–14428
Filed 6–17–14; 11:15 am]
Billing code 3295–F4

Presidential Documents

Executive Order 13669 of June 13, 2014

2014 Amendments to the Manual for Courts-Martial, United States

By the authority vested in me as President by the Constitution and the laws of the United States of America, including chapter 47 of title 10, United States Code (Uniform Code of Military Justice, 10 U.S.C. 801–946), and in order to prescribe amendments to the Manual for Courts-Martial, United States, prescribed by Executive Order 12473 of April 13, 1984, as amended, it is hereby ordered as follows:

Section 1. Part II, the Discussion for Part II, and the Analysis for Part II of the Manual for Courts-Martial, United States, are amended as described in the Annex attached and made a part of this order.

Sec. 2. These amendments shall take effect as of the date of this order, subject to the following:

(a) Nothing in these amendments shall be construed to make punishable any act done or omitted prior to the effective date of this order that was not punishable when done or omitted.

(b) Nothing in these amendments shall be construed to invalidate any nonjudicial punishment proceedings, restraint, investigation, referral of charges, trial in which arraignment occurred, or other action begun prior to the effective date of this order, and any such nonjudicial punishment, restraint, investigation, referral of charges, trial, or other action may proceed in the same manner and with the same effect as if these amendments had not been prescribed.

THE WHITE HOUSE,

June 13, 2014.

Billing code 3295–F4–P

ANNEX

Section 1. Part II of the Manual for Courts-Martial, United States, is amended as follows:

(a) R.C.M. 405(f)(10) is amended to read as follows:

"(10) Have evidence, including documents or physical evidence, produced as provided under subsection (g) of this rule;".

(b) R.C.M. 405(g)(1)(B) is amended to read as follows:

"(B) *Evidence*. Subject to Mil. R. Evid., Section V, evidence, including documents or physical evidence, which is relevant to the investigation and not cumulative, shall be produced if reasonably available. Such evidence includes evidence requested by the accused, if the request is timely and in compliance with this rule. As soon as practicable after receipt of a request by the accused for information that may be protected under Mil. R. Evid. 505 or 506, the investigating officer shall notify the person who is authorized to issue a protective order under subsection (g)(6) of this rule, and the convening authority, if different. Evidence is reasonably available if its significance outweighs the difficulty, expense, delay, and effect on military operations of obtaining the evidence."

(c) R.C.M. 405(g)(2)(C) is amended to read as follows:

"(C) *Evidence generally*. The investigating officer shall make an initial determination whether evidence is reasonably available. If the investigating officer decides that it is not

reasonably available, the investigating officer shall inform the parties."

(d) R.C.M. 405(g)(2)(C)(i) is inserted to read as follows:

"(i) *Evidence under the control of the Government.* Upon the investigating officer's determination that evidence is reasonably available, the custodian of the evidence shall be requested to provide the evidence. A determination by the custodian that the evidence is not reasonably available is not subject to appeal by the accused, but may be reviewed by the military judge under R.C.M. 906(b)(3)."

(e) R.C.M. 405(g)(2)(C)(ii) is inserted to read as follows:

"(ii) *Evidence not under the control of the Government.* Evidence not under the control of the Government may be obtained through noncompulsory means or by subpoena duces tecum issued pursuant to procedures set forth in R.C.M. 703(f)(4)(B). A determination by the investigating officer that the evidence is not reasonably available is not subject to appeal by the accused, but may be reviewed by the military judge under R.C.M. 906(b)(3)."

(f) R.C.M. 405(i) is amended to read as follows:

"(i) *Military Rules of Evidence.* The Military Rules of Evidence do not apply in pretrial investigations under this rule except as follows:

(1) Military Rules of Evidence 301, 302, 303, 305, and Section V shall apply in their entirety.

(2) Military Rule of Evidence 412 shall apply in any case defined as a sexual offense in Mil. R. Evid. 412(d).

(3) In applying these rules to a pretrial investigation, the term "military judge," as used in these rules, shall mean the investigating officer, who shall assume the military judge's powers to exclude evidence from the pretrial investigation, and who shall, in discharging this duty, follow the procedures set forth in the rules cited in paragraphs (1) and (2)."

(g) R.C.M. 703(e)(2)(B) is amended to read as follows:

"(B) *Contents.* A subpoena shall state the command by which the proceeding is directed, and the title, if any, of the proceeding. A subpoena shall command each person to whom it is directed to attend and give testimony at the time and place specified therein. A subpoena may also command the person to whom it is directed to produce books, papers, documents, data, or other objects or electronically stored information designated therein at the proceeding or at an earlier time for inspection by the parties. A subpoena issued for an investigation pursuant to Article 32 shall not command any person to attend or give testimony at an Article 32 investigation."

(h) R.C.M. 703(e)(2)(C) is amended to read as follows:

"(C) *Who may issue.*

(1) A subpoena to secure evidence may be issued by:

(a) the summary court-martial;

(b) detailed counsel representing the United States at an Article 32 investigation;

(c) the investigating officer appointed under R.C.M. 405(d)(1);

(d) after referral to a court-martial, detailed trial counsel;

(e) the president of a court of inquiry; or

(f) an officer detailed to take a deposition.

(2) A subpoena to secure witnesses may be issued by:

(a) the summary court-martial;

(b) after referral to a court-martial, detailed trial counsel;

(c) the president of a court of inquiry; or

(d) an officer detailed to take a deposition.

(i) R.C.M. 703(e)(2)(D) is amended to read as follows:

"(D) *Service.* A subpoena may be served by the person authorized by this rule to issue it, a United States Marshal, or any other person who is not less than 18 years of age. Service shall be made by delivering a copy of the subpoena to the person named and by providing to the person named travel orders and a means for reimbursement for fees and mileage as may be

prescribed by the Secretary concerned, or in the case of hardship resulting in the subpoenaed witness's inability to comply with the subpoena absent initial government payment, by providing to the person named travel orders, fees, and mileage sufficient to comply with the subpoena in rules prescribed by the Secretary concerned."

(j) R.C.M. 703(e)(2)(G)(ii) is amended to read as follows:

"(ii) *Requirements.* A warrant of attachment may be issued only upon probable cause to believe that the witness was duly served with a subpoena, that the subpoena was issued in accordance with these rules, that a means of reimbursement of fees and mileage was provided to the witness or advanced to the witness in cases of hardship, that the witness is material, that the witness refused or willfully neglected to appear at the time and place specified on the subpoena, and that no valid excuse is reasonably apparent for the witness's failure to appear."

(k) R.C.M. 703(f)(4)(B) is amended to read as follows:

"(B) *Evidence not under the control of the Government.* Evidence not under the control of the Government may be obtained by subpoena issued in accordance with subsection (e)(2) of this rule. A subpoena duces tecum to produce books, papers, documents, data, or other objects or electronically stored information for a pretrial investigation pursuant to Article 32 may be issued, following the convening authority's order

directing such pretrial investigation, by either the investigating officer appointed under R.C.M. 405(d)(1) or the detailed counsel representing the United States. A person in receipt of a subpoena duces tecum for an Article 32 hearing need not personally appear in order to comply with the subpoena."

(l) R.C.M. 1103(b)(3) is amended by inserting new subsection (N) after R.C.M. 1103(b)(3)(M) as follows:

"(N) Documents pertaining to the receipt of the record of trial by the victim pursuant to subsection (g)(3) of this rule."

(m) R.C.M. 1103(g) is amended by inserting new subsection (3) after R.C.M. 1103(g)(2) as follows:

"(3) *Cases involving sexual offenses.*

(A) "Victim" defined. For the purposes of this rule, a victim is a person who suffered a direct physical, emotional, or pecuniary harm as a result of matters set forth in a charge or specification; and is named in a specification under Article 120, Article 120b, Article 120c, Article 125, or any attempt to commit such offense in violation of Article 80.

(B) *Scope; qualifying victim.* In a general or special court-martial, a copy of the record of trial shall be given free of charge to a victim as defined in subparagraph (A) for a specification identified in subparagraph (A) that resulted in any finding under R.C.M. 918(a)(1). If a victim is a minor, a

copy of the record of trial shall instead be provided to the parent or legal guardian of the victim.

(C) *Notice.* In accordance with regulations of the Secretary concerned, and no later than authentication of the record, trial counsel shall cause each qualifying victim to be notified of the opportunity to receive a copy of the record of trial. Qualifying victims may decline receipt of such documents in writing and any written declination shall be attached to the original record of trial.

(D) *Documents to be provided.* For purposes of this subsection, the record of trial shall consist of documents described in subsection (b)(2) of this rule, except for proceedings described in subsection (e) of this rule, in which case the record of trial shall consist of items described in subsection (e). Matters attached to the record as described in subsection (b)(3) of this rule are not required to be provided."

(n) R.C.M. 1104(b)(1) is amended by inserting new subsection (E) after the Discussion section to R.C.M. 1104(b)(1)(D)(iii)(d) as follows:

"(E) *Victims of Sexual Assault.* Qualifying victims, as defined in R.C.M. 1103(g)(3)(A), shall be served a copy of the record of trial in the same manner as the accused under subsection (b) of this rule. In accordance with regulations of the Secretary concerned:

(i) A copy of the record of trial shall be provided to each qualifying victim as soon as it is authenticated or, if the victim requests, at a time thereafter. The victim's receipt of the record of trial, including any delay in receiving it, shall be documented and attached to the original record of trial.

(ii) A copy of the convening authority's action as described in R.C.M. 1103(b)(2)(D)(iv) shall be provided to each qualifying victim as soon as each document is prepared. If the victim makes a request in writing, service of the record of trial may be delayed until the action is available.

(iii) Classified information pursuant to subsection (b)(1)(D) of this rule, sealed matters pursuant to R.C.M. 1103A, or other portions of the record the release of which would unlawfully violate the privacy interests of any party, to include those afforded by 5 U.S.C. § 552a, the Privacy Act of 1974, shall not be provided. Matters attached to the record as described in R.C.M. 1103(b)(3) are not required to be provided."

(o) R.C.M. 1105A is newly inserted and reads as follows:

"Rule 1105A. Matters submitted by a crime victim

(a) *In general*. A crime victim of an offense tried by any court-martial shall have the right to submit a written statement to the convening authority after the sentence is adjudged.

(b) *"Crime victim" defined*. For purposes of this rule, a crime victim is a person who has suffered direct physical, emotional, or pecuniary harm as a result of the commission of an offense of which the accused was found guilty, and on which the convening authority is taking action under R.C.M. 1107. When a victim is under 18 years of age, incompetent, incapacitated, or deceased, the term includes one of the following (in order of precedence): a spouse, legal guardian, parent, child, sibling, or similarly situated family member. For a victim that is an institutional entity, the term includes an authorized representative of the entity.

(c) *Format of statement*. The statement shall be in writing, and signed by the crime victim. Statements may include photographs, but shall not include video, audio, or other media.

(d) *Timing of statement*.

(1) *General and special courts-martial*. The crime victim shall submit the statement to the convening authority's staff judge advocate or legal officer no later than 10 days after the later of:

(A) if the victim is entitled to a copy of the record of proceedings in accordance with Article 54(e), UCMJ, the date on which the victim receives an authenticated copy of the record of trial or waives the right to receive such a copy; or

(B) the date on which the recommendation of the staff judge advocate or legal officer is served on the victim.

(2) *Summary courts-martial*. The crime victim shall submit the statement to the summary court-martial officer no later than 7 days after the sentence is announced.

(3) Extensions. If a victim shows that additional time is required for submission of matters, the convening authority or other person taking action, for good cause, may extend the submission period for not more than an additional 20 days.

(e) *Notice*. Subject to such regulations as the Secretary concerned may prescribe, trial counsel or the summary court-martial officer shall make reasonable efforts to inform crime victims of their rights under this rule, and shall advise such crime victims on the manner in which their statements may be submitted.

(f) *Waiver*.

(1) *Failure to submit a statement*. Failure to submit a statement within the time prescribed by this rule shall be deemed a waiver of the right to submit such a statement.

(2) *Submission of a statement*. Submission of a statement under this rule shall be deemed a waiver of the right to submit an additional statement.

(3) *Written waiver.* A crime victim may expressly waive, in writing, the right to submit a statement under this rule. Once filed, such waiver may not be revoked."

(p) R.C.M. 1106(a) is amended to read as follows:

"(a) *In general.* Before the convening authority takes action under R.C.M. 1107 on a record of trial by general court-martial, on a record of trial by special court-martial that includes a sentence to a bad-conduct discharge or confinement for one year, or on a record of trial by special court-martial in which a victim is entitled to submit a statement pursuant to R.C.M. 1105A, that convening authority's staff judge advocate or legal officer shall, except as provided in subsection (c) of this rule, forward to the convening authority a recommendation under this rule."

(q) R.C.M. 1106(d)(3) is amended to read as follows:

"(3) *Required contents.* Except as provided in subsection (e), the staff judge advocate or legal advisor shall provide the convening authority with a copy of the report of results of the trial, setting forth the findings, sentence, and confinement credit to be applied; a copy or summary of the pretrial agreement, if any; a copy of any statement submitted by a crime victim pursuant to R.C.M. 1105A; any recommendation for clemency by the sentencing authority made in conjunction with the

announced sentence; and the staff judge advocate's concise recommendation."

(r) R.C.M. 1106(f) and (f)(1) are amended to read as follows:

"(f) *Service of recommendation on defense counsel, accused, and victim; defense response.*

(1) *Service of recommendation on defense counsel, accused, and victim.* Before forwarding the recommendation and the record of trial to the convening authority for action under R.C.M. 1107, the staff judge advocate or legal officer shall cause a copy of the recommendation to be served on the counsel for the accused. A separate copy will be served on the accused. If it is impracticable to serve the recommendation on the accused for reasons including the transfer of the accused to a different place, the unauthorized absence of the accused, or military exigency, or if the accused so requests on the record at the court-martial or in writing, the accused's copy shall be forwarded to the accused's defense counsel. A statement shall be attached to the record explaining why the accused was not served personally. If the accused was found guilty of any offense that resulted in direct physical, emotional, or pecuniary harm to a victim or victims, a separate copy of the recommendation will be served on that victim or those victims. When a victim is under 18 years of age, incompetent, incapacitated, deceased, or otherwise unavailable, service shall be made on one of the

following (in order of precedence): the victim's attorney, spouse, legal guardian, parent, child, sibling, or similarly situated family member. For a victim that is an institutional entity, service shall be made on an authorized representative of the entity.

(s) R.C.M. 1106(f)(4) is amended to read as follows:

"(4) *Response*. Counsel for the accused may submit, in writing, corrections or rebuttal to any matter in the recommendation and its enclosures believed to be erroneous, inadequate, or misleading, and may comment on any other matter."

(t) R.C.M. 1107(b)(3)(A) is amended by inserting new subsection (iv) immediately after R.C.M. 1107(b)(3)(A)(iii) as follows:

"(iv) Any statement submitted by a crime victim pursuant to R.C.M. 1105A."

(u) R.C.M. 1107(b)(3) is amended by inserting new subsection (C) immediately after R.C.M. 1107(b)(3)(B)(iii) as follows:

"(C) *Prohibited matters*. The convening authority shall not consider any matters that relate to the character of a victim unless such matters were presented as evidence at trial and not excluded at trial."

(v) R.C.M. 1306(a) is amended to read as follows:

"(a) *Matters submitted*.

(1) *By a crime victim*. After a sentence is adjudged, a crime victim may submit a written statement to the convening

authority in accordance with R.C.M. 1105A. A statement submitted by a crime victim shall be immediately served on the accused.

(2) *By the accused*. After a sentence is adjudged, the accused may submit written matters to the convening authority in accordance with R.C.M. 1105."

Sec. 2. The Discussion to Part II of the Manual for Courts-Martial, United States, is amended as follows:

(a) The Discussion immediately following R.C.M. 306(b) is amended to read as follows:

"The disposition decision is one of the most important and difficult decisions facing a commander. Many factors must be taken into consideration and balanced, including, to the extent practicable, the nature of the offenses, any mitigating or extenuating circumstances, the views of the victim as to disposition, any recommendations made by subordinate commanders, the interest of justice, military exigencies, and the effect of the decision on the accused and the command. The goal should be a disposition that is warranted, appropriate, and fair.

In deciding how an offense should be disposed of, factors the commander should consider, to the extent they are known, include:

(A) the nature of and circumstances surrounding the offense and the extent of the harm caused by the offense, including the

offense's effect on morale, health, safety, welfare, and discipline;

(B) when applicable, the views of the victim as to disposition;

(C) existence of jurisdiction over the accused and the offense;

(D) availability and admissibility of evidence;

(E) the willingness of the victim or others to testify;

(F) cooperation of the accused in the apprehension or prosecution of another accused;

(G) possible improper motives or biases of the person(s) making the allegation(s);

(H) availability and likelihood of prosecution of the same or similar and related charges against the accused by another jurisdiction;

(I) appropriateness of the authorized punishment to the particular accused or offense.

(b) The Discussion immediately following R.C.M. 405(g)(1)(B) is amended to read as follows:

"In preparing for the investigation, the investigating officer should consider what evidence, including evidence that may be obtained by subpoena duces tecum, will be necessary to prepare a thorough and impartial investigation. The investigating officer should consider, as to potential witnesses, whether their

personal appearance will be necessary. Generally, personal appearance is preferred, but the investigating officer should consider whether, in light of the probable importance of a witness's testimony, an alternative to testimony under subsection (g)(4)(A) of this rule would be sufficient.

After making a preliminary determination of what witnesses will be produced and other evidence considered, the investigating officer should notify the defense and inquire whether it requests the production of other witnesses or evidence. In addition to witnesses for the defense, the defense may request production of witnesses whose testimony would favor the prosecution.

Once it is determined what witnesses the investigating officer intends to call, it must be determined whether each witness is reasonably available. That determination is a balancing test. The more important the testimony of the witness, the greater the difficulty, expense, delay, or effect on military operations must be to permit nonproduction. For example, the temporary absence of a witness on leave for 10 days would normally justify using an alternative to that witness's personal appearance if the sole reason for the witness's testimony was to impeach the credibility of another witness by reputation evidence, or to establish a mitigating character trait of the accused. On the other hand, if the same witness was the only eyewitness to the

offense, personal appearance would be required if the defense requested it and the witness is otherwise reasonably available. The time and place of the investigation may be changed if reasonably necessary to permit the appearance of a witness. Similar considerations apply to the production of evidence, including evidence that may be obtained by subpoena duces tecum.

If the production of witnesses or evidence would entail substantial costs or delay, the investigating officer should inform the commander who directed the investigation.

The provision in (B), requiring the investigating officer to notify the appropriate authorities of requests by the accused for information privileged under Mil. R. Evid. 505 or 506, is for the purpose of placing the appropriate authority on notice that an order, as authorized under subsection (g)(6), may be required to protect whatever information the government may decide to release to the accused."

(c) The Discussion immediately following R.C.M. 405(g)(2)(B) is amended to read as follows:

"The investigating officer should initially determine whether a civilian witness is reasonably available without regard to whether the witness is willing to appear. If the investigating officer determines that a civilian witness is apparently reasonably available, the witness should be invited to attend

and, when appropriate, informed that necessary expenses will be paid.

If the witness refuses to testify, the witness is not reasonably available because civilian witnesses may not be compelled to attend a pretrial investigation. Under subsection (g)(3) of this rule, civilian witnesses may be paid for travel and associated expenses to testify at a pretrial investigation. Except for use in support of the deposition of a witness under Article 49, UCMJ, and ordered pursuant to R.C.M. 702(b), the investigating officer and any government representative to an Article 32, UCMJ, proceeding does not possess authority to issue a subpoena to compel against his or her will a civilian witness to appear and provide testimony."

(d) The Discussion immediately following R.C.M. 405(g)(2)(C)(i) is amended to read as follows:

"Evidence shall include documents and physical evidence that are relevant to the investigation and not cumulative. *See* subsection (g)(1)(B). The investigating officer may discuss factors affecting reasonable availability with the custodian and with others. If the custodian determines that the evidence is not reasonably available, the reasons for that determination should be provided to the investigating officer."

(e) The following Discussion is inserted immediately after R.C.M. 405(g)(2)(C)(ii):

"A subpoena duces tecum to produce books, papers, documents, data, electronically stored information, or other objects for a pretrial investigation pursuant to Article 32 may be issued by the investigating officer or counsel representing the United States. *See* R.C.M. 703(f)(4)(B).

The investigating officer may find that evidence is not reasonably available if: the subpoenaed party refuses to comply with the duly issued subpoena duces tecum; the evidence is not subject to compulsory process; or the significance of the evidence is outweighed by the difficulty, expense, delay, and effect on military operations of obtaining the evidence."

(f) The Discussion immediately following R.C.M. 405(g)(3) is amended to read as follows:

"*See* Department of Defense Joint Travel Regulations, Vol. 2, paragraph C7055."

(g) The Discussion immediately following R.C.M. 405(i) is amended to read as follows:

"With regard to all evidence, the investigating officer should exercise reasonable control over the scope of the inquiry. *See* subsection (e) of this rule. An investigating officer may consider any evidence, even if that evidence would not be admissible at trial. However, see subsection (g)(4) of this rule as to limitations on the ways in which testimony may be presented. Certain rules relating to the form of testimony that

may be considered by the investigating officer appear in subsection (g) of this rule.

Mil. R. Evid. 412 evidence, including closed hearing testimony, must be protected pursuant to the Privacy Act of 1974, 5 U.S.C. § 552a. Evidence deemed admissible by the investigating officer should be made a part of the report of investigation. *See* subsection (j)(2)(C), *infra*. Evidence deemed inadmissible, and the testimony taken during the closed hearing, should not be included in the report of investigation and should be safeguarded. The investigating officer and counsel representing the United States are responsible for careful handling of any such evidence to prevent indiscriminate viewing or disclosure. Although R.C.M. 1103A does not apply, its requirements should be used as a model for safeguarding inadmissible evidence and closed hearing testimony. The convening authority and the appropriate judge advocate are permitted to review such safeguarded evidence and testimony. *See* R.C.M. 601(d)(1)."

(h) The Discussion immediately following R.C.M. 703(e)(2)(B) is amended to read as follows:

"A subpoena may not be used to compel a witness to appear at an examination or interview before trial, but a subpoena may be used to obtain witnesses for a deposition or a court of inquiry. In accordance with subsection (f)(4)(B) of this rule, a subpoena

duces tecum to produce books, papers, documents, data, or other objects or electronically stored information for pretrial investigation pursuant to Article 32 may be issued, following the convening authority's order directing such pretrial investigation, by either the investigating officer appointed under R.C.M. 405(d)(1) or the counsel representing the United States.

A subpoena normally is prepared, signed, and issued in duplicate on the official forms. *See* Appendix 7 for an example of a subpoena with certificate of service (DD Form 453) and a Travel Order (DD Form 453-1)."

(i) The Discussion immediately following R.C.M. 703(e)(2)(D) is amended to read as follows:

"If practicable, a subpoena should be issued in time to permit service at least 24 hours before the time the witness will have to travel to comply with the subpoena.

Informal service. Unless formal service is advisable, the person who issued the subpoena may mail it to the witness in duplicate, enclosing a postage-paid envelope bearing a return address, with the request that the witness sign the acceptance of service on the copy and return it in the envelope provided. The return envelope should be addressed to the person who issued the subpoena. The person who issued the subpoena should include with it a statement to the effect that the rights of the witness

to fees and mileage will not be impaired by voluntary compliance with the request and that a voucher for fees and mileage will be delivered to the witness promptly on being discharged from attendance.

Formal service. Formal service is advisable whenever it is anticipated that the witness will not comply voluntarily with the subpoena. Appropriate fees and mileage must be paid or tendered. *See* Article 47. If formal service is advisable, the person who issued the subpoena must assure timely and economical service. That person may do so by serving the subpoena personally when the witness is in the vicinity. When the witness is not in the vicinity, the subpoena may be sent in duplicate to the commander of a military installation near the witness. Such commanders should give prompt and effective assistance, issuing travel orders for their personnel to serve the subpoena when necessary.

Service should ordinarily be made by a person subject to the code. The duplicate copy of the subpoena must have entered upon it proof of service as indicated on the form and must be promptly returned to the person who issued the subpoena. If service cannot be made, the person who issued the subpoena must be informed promptly. A stamped, addressed envelope should be provided for these purposes.

For purposes of this Rule, *hardship* is defined as any situation which would substantially preclude reasonable efforts to appear that could be solved by providing transportation or fees and mileage to which the witness is entitled for appearing at the hearing in question."

(j) The Discussion immediately following R.C.M. 703(e)(2)(G)(i) is amended to read as follows:

"A warrant of attachment (DD Form 454) may be used when necessary to compel a witness to appear or produce evidence under this rule. A warrant of attachment is a legal order addressed to an official directing that official to have the person named in the order brought before a court.

Subpoenas issued under R.C.M. 703 are Federal process and a person not subject to the code may be prosecuted in a Federal civilian court under Article 47 for failure to comply with a subpoena issued in compliance with this rule and formally served.

Failing to comply with such a subpoena is a felony offense, and may result in a fine or imprisonment, or both, at the discretion of the district court. The different purposes of the warrant of attachment and criminal complaint under Article 47 should be borne in mind. The warrant of attachment, available without the intervention of civilian judicial proceedings, has as its purpose the obtaining of the witness's presence,

testimony, or documents. The criminal complaint, prosecuted through the civilian Federal courts, has as its purpose punishment for failing to comply with process issued by military authority. It serves to vindicate the military interest in obtaining compliance with its lawful process.

For subpoenas issued for a pretrial investigation pursuant to Article 32 under subsection (f)(4)(B), the general court-martial convening authority with jurisdiction over the case may issue a warrant of attachment to compel production of documents."

(k) The Discussion immediately following R.C.M. 703(f)(1) is amended to read as follows:

"Relevance is defined by Mil. R. Evid. 401. Relevant evidence is necessary when it is not cumulative and when it would contribute to a party's presentation of the case in some positive way on a matter in issue. A matter is not in issue when it is stipulated as a fact. The discovery and introduction of classified or other government information is controlled by Mil. R. Evid. 505 and 506."

(l) The following Discussion is added immediately after R.C.M. 703(f)(4)(B):

"The National Defense Authorization Act for Fiscal Year 2012, P.L. 112-81, § 542, amended Article 47 to allow the issuance of subpoenas duces tecum for Article 32 hearings. Although the amended language cites Article 32(b), this new subpoena power

extends to documents subpoenaed by the investigating officer and counsel representing the United States, whether or not requested by the defense."

(m) The following Discussion is inserted immediately after R.C.M. 1103(b)(3)(N):

"Per R.C.M. 1114(f), consult service regulations for distribution of promulgating orders."

(n) The following Discussion is added immediately after R.C.M. 1103(g)(3)(B):

"This rule is not intended to limit the Services' discretion to provide records of trial to other individuals."

(o) The following Discussion is inserted immediately after R.C.M. 1103(g)(3)(D):

"Subsections (b)(3)(N) and (g)(3) of this rule were added to implement Article 54(e), UCMJ, in compliance with the National Defense Authorization Act for Fiscal Year 2012 (P.L. 112-81, § 586). Service of a copy of the record of trial on a victim is prescribed in R.C.M. 1104(b)(1)(E)."

(p) The following Discussion is added immediately after R.C.M. 1104(b)(1)(E):

"Subsection (b)(1)(E) of this rule was added to implement Article 54(e), UCMJ, in compliance with the National Defense Authorization Act for Fiscal Year 2012 (P.L. 112-81, § 586). The

content of the victim's record of trial is prescribed in R.C.M. 1103(g)(3)(D).

Promulgating orders are to be distributed in accordance with R.C.M. 1114(f)."

(q) The following Discussion is added immediately after R.C.M. 1105A(c):

"Statements should be submitted to the convening authority's staff judge advocate or legal officer, or, in the case of a summary court-martial, to the summary court-martial officer."

(r) The Discussion immediately after R.C.M. 1106(d)(3) is amended to read as follows:

"The recommendation required by this rule need not include information regarding the recommendations for clemency. *See* R.C.M. 1105(b)(2)(D), which pertains to clemency recommendations that may be submitted by the accused to the convening authority.

The recommendation is only required to include a crime victim's statement if the statement is submitted by the crime victim under the provisions of R.C.M. 1105A. The recommendation is not required to contain any other statements that a crime victim may have made on other occasions unless those previous statements are submitted by the crime victim under the provisions of R.C.M. 1105A."

(s) The Discussion immediately after R.C.M. 1106(f)(7) is amended to read as follows:

""New matter" includes discussion of the effect of new decisions on issues in the case, matter from outside the record of trial, and issues not previously discussed. "New matter" does not ordinarily include any discussion by the staff judge advocate or legal officer of the correctness of the initial defense comments on the recommendation. The method of service and the form of the proof of service are not prescribed and may be by any appropriate means. *See* R.C.M. 1103(b)(3)(G). For example, a certificate of service, attached to the record of trial, would be appropriate when the accused is served personally. If a victim statement, submitted under R.C.M. 1105A, is served on the accused prior to service of the recommendation, then that statement shall not be considered a "new matter" when it is again served on the accused as an enclosure to the recommendation."

Sec. 3. Appendix 21 of the Manual for Courts-Martial, United States, Analysis of Rules for Courts-Martial, is amended as follows:

R.C.M. 1107, after the paragraph beginning with the words "Subsection (3)(A)(i)," insert the following language:

"*2014 Amendment*. The prohibition against considering matters that relate to the character of a victim expands upon the prohibition against considering "submitted" matters that is

set forth in section 1706(b) of the National Defense Authorization Act for Fiscal Year 2014, Pub. L. No. 113-66, 127 Stat. 961 (2013). This revision does not incorporate the word "submitted" from section 1706(b), in order to afford greater protection to the victim by prohibiting convening authority consideration of any evidence of a victim's character not admitted into evidence at trial, no matter the source."

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Presidential Documents

Executive Order 13670 of June 14, 2014

Establishing an Emergency Board To Investigate Disputes Between the Southeastern Pennsylvania Transportation Authority and Certain of Its Employees Represented by Certain Labor Organizations

Disputes exist between the Southeastern Pennsylvania Transportation Authority (SEPTA) and certain of its employees represented by certain labor organizations. The labor organizations involved in these disputes are designated on the attached list, which is made part of this order.

The disputes heretofore have not been adjusted under the provisions of the Railway Labor Act, as amended, 45 U. S. C. 151–188 (RLA).

A party empowered by the RLA has requested that the President establish an emergency board pursuant to section 9A of the RLA (45 U. S. C. 159a).

Section 9A(c) of the RLA provides that the President, upon such request, shall appoint an emergency board to investigate and report on the disputes.

NOW, THEREFORE, by the authority vested in me as President by the Constitution and the laws of the United States, including section 9A of the RLA, it is hereby ordered as follows:

Section 1. *Establishment of Emergency Board (Board).* There is established, effective 12:01 a.m. eastern daylight time on June 15, 2014, a Board of three members to be appointed by the President to investigate and report on these disputes. No member shall be pecuniarily or otherwise interested in any organization of railroad employees or any carrier. The Board shall perform its functions subject to the availability of funds.

Sec. 2. *Report.* The Board shall report to the President with respect to the disputes within 30 days of its creation.

Sec. 3. *Maintaining Conditions.* As provided by section 9A(c) of the RLA, for 120 days from the date of the creation of the Board, no change in the conditions out of which the disputes arose shall be made by the parties to the controversy, except by agreement of the parties.

Sec. 4. *Records Maintenance.* The records and files of the Board are records of the Office of the President and upon the Board's termination shall be maintained in the physical custody of the National Mediation Board.

Sec. 5. *Expiration.* The Board shall terminate upon the submission of the report provided for in section 2 of this order.

THE WHITE HOUSE,
June 14, 2014.

Billing code 3295–F4–P

LABOR ORGANIZATIONS

Brotherhood of Locomotive Engineers and Trainmen
International Brotherhood of Electrical Workers

[FR Doc. 2014–14432
Filed 6–17–14; 11:15 a.m.]
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