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SMALL BUSINESS ADMINISTRATION

13 CFR Chapter I

RIN 3245–AF84

Small Business Innovation Research Program Policy Directive

AGENCY: Small Business Administration.

ACTION: Notice of amendments to final policy directive.

SUMMARY: The U.S. Small Business Administration (SBA) is amending its Small Business Innovation Research (SBIR) Program Policy Directive in response to public comments SBA received on the final SBIR Policy Directive, published on August 6, 2012. SBA is also making several minor clarifying changes to ensure that the SBIR participants clearly understand certain program requirements.

DATES: These amendments to the SBIR Policy Directive are effective January 8, 2014.

FOR FURTHER INFORMATION CONTACT: Edsel Brown, Assistant Director, Office of Innovation, at (202) 401–6365 or *technet@sba.gov.*

SUPPLEMENTARY INFORMATION: On December 31, 2011, the President signed into law the National Defense Authorization Act for Fiscal Year 2012 (Defense Reauthorization Act), Public Law 112–81, 125–Stat. 1298. Section 5001, Division E of the Defense Reauthorization Act contains the SBIR/STTR Reauthorization Act of 2011 (Reauthorization Act), which amended the Small Business Act and made several amendments to the SBIR Program. The Reauthorization Act required SBA to issue amendments to the SBIR Policy Directive and publish the amendments in the **Federal Register** within 180 days of when the Reauthorization Act was passed.

On August 6, 2012, SBA published a final SBIR Policy Directive implementing the various provisions of the Reauthorization Act at 77 FR 46806. The directive made several key changes to the SBIR Program relating to eligibility, the SBIR award process, SBIR Program administration, and fraud, waste and abuse. Although the SBIR Policy Directive is intended for use by the SBIR participating agencies, SBA believed that public input on the directive from all parties involved in the program would be invaluable. Therefore, SBA sought public comments on the final directive, and stated that it may amend the directive in response to these comments at a later time.

Response to Comments

In response to this request, SBA received comments on various parts of the directive. Several comments recommended that SBA strengthen and clarify the Policy Directive language with regard to SBIR data rights and the obligation of federal agencies to give a preference in contracting to SBIR awardees for follow-on Phase III work. SBA agrees that these are areas of the SBIR policy that are vital to the program and require clarification and improvement. SBA continues to evaluate these issues and will address them in a subsequent Policy Directive revision.

SBA also received comments that the definition of Essentially Equivalent Work in section 3(j) of the Policy Directive should be changed to be more in line with the common usage. The concern is that the definition in the Policy Directive is more stringent than the norm for Government contracting and places a higher burden on the small businesses participating in the SBIR program. The commenter, however, did not provide SBA with this commonly used definition and SBA could not find one. Therefore, SBA has not modified the definition at this time. However, SBA has revised the language in section 7(d) of the Directive to further clarify funding of ''essentially equivalent work.''

Section 4(a)(3) of the Policy Directive, ''Agency benchmarks for progress towards commercialization'' sets forth the program policy regarding an eligibility requirement for Phase I awards. SBA received comments requesting clarification of the time periods used to calculate the transition rate and commercialization rate benchmark requirements. Commenters also requested clarification about how agencies determine which firms must comply with the transition rate and commercialization rate benchmarks. In response to these comments, SBA revised and reorganized section 4(a)(3) to clarify several procedural elements about the benchmark determinations and enhance its readability.

Section 4(a)(3) clarifies the time periods used to calculate awardee rates of transition from Phase I to Phase II and provides two examples of the calculation. While the rate is calculated using Phase I awards received in the most recent 5,10, or 15-year period (agencies choose which period they use), excluding the most recently completed fiscal year; the period used when counting the Phase II awards is lagged one year. That is, when calculating the number of Phase I awards received over a particular time period, the time period evaluated does not include the most recently completed fiscal year; however, when calculating the number of Phase II awards received, the time period evaluated does include the most recently completed fiscal year but does not include the first year of the period evaluated for Phase I awards received. The period used to calculate Phase II awards is lagged one-year because it is unlikely that a new Phase I would transition to a Phase II within the same year. SBA also clarified that the Phase II transition benchmark requirement applies only to awardees that have received more than 20 Phase I awards over the applicable time period and that the commercialization benchmark applies only to firms that received more than 15 Phase II awards over the applicable time period.

Based on additional input from the agencies participating in the SBIR program, SBA also revised several procedural elements of the Phase II transition benchmark requirement in section 4(a)(3) to simplify the process for small businesses and reduce the administrative burden on the agencies. Specifically, in section 4(a)(3)(iii), SBA changed the start date for the one-year ineligibility period for firms that do not meet the benchmarks. The date was changed from the date of application submission to June 1st of each year. SBA made this change for several reasons: (1) It is a clearly defined period for affected small businesses; (2) to

provide sufficient time for agencies to enter fully verified award data from the prior fiscal year into the TechNet database; and (3) to eliminate the need for agencies to track multiple periods of ineligibility. SBA will use its TechNet Data system to generate the list of companies that do not meet agency Phase II transition benchmarks and provide this list to the agencies each year on June 1. Finally, SBA also added a procedure to notify awardee firms if they are on the ineligible list and to enable firms to provide feedback directly to SBA if they believe their rate was calculated using incomplete award information.

Some respondents asked if the provision in section 4(b)(5) allowing one Sequential Phase II award included supplementary awards such as Phase 2.5 or Phase IIb awards in the definition of a Phase II award. SBA relocated the language at section 4(b)(6) to new section 4(b)(8) and added new section 4(b)(6) to clarify SBA's policy on supplemental phase II awards. Section 4(b)(6) now clarifies how Phase II award amounts are calculated when supplemental awards are issued. Furthermore, section 4(b)(6) specifies that all supplementary awards, such as a Phase IIb, must be linked to either an initial Phase II or a sequential Phase II award and is added to the amount of that award for the purpose of determining the size of the Phase II award. This means that all supplementary Phase II awards including options, enhancements, administrative supplements, and Phase IIb-type programs are considered as part of the initial Phase II or sequential Phase II from which they derive and are therefore subject to the Phase II per-award guideline amount of $1 million and limit of $1.5 million.

SBA repeated the language in section 9(d)(2) in new section 4(b)(7), which explains how a Phase I awardee may receive an award from one agency and also may receive a subsequent Phase II award from another agency. SBA also clarified in section 4(b)(7) that the same process applies to a second, sequential Phase II award that follows an initial Phase II award from a different agency. This policy is relevant to interagency actions, which are found at section 9 of the Policy Directive, and also to Phase II awards, which is found at section 4 of the Policy Directive.

SBA received comments concerning section 9 of the Policy Directive, which address measures to prevent fraud, waste and abuse in the program. The respondents commented that the administrative requirements contained in section 9 may be too stringent and may discourage small businesses from applying. SBA notes that it developed these requirements, including the procedures and requirements for certification, in consultation with the Council of Inspectors General on Integrity and Efficiency. SBA believes that these provisions can help reduce fraud, waste and abuse in the program and does not think these provisions should be changed at this time.

SBA received comments on the Department of Defense's (DoD's) Commercialization Readiness Program, outlined in section 12(b) of the SBIR Policy Directive. In response to comments that agency efforts to increase transitions to Phase III could reduce the innovative nature of SBIR awards, SBA has added that when DoD reports on its Phase II insertion incentives, it should note efforts to ensure that such incentives do not act to shift the focus of SBIR Phase II awards away from relatively high-risk innovation projects. SBA also amended the provisions relating to the use of SBIR funds for the DoD Commercialization Readiness Program. According to section 1615 of the National Defense Authorization Act for Fiscal Year 2013 (NDAA), Public Law 112–239, 126 Stat. 1632, DoD has the authority to use 1% of its SBIR funding for purposes of administering the Commercialization Readiness Program.

A number of comments asked us to change features that, because they are required by statute, we were not able to modify.

Miscellaneous Changes

The inadvertent omission of the term ''extramural'' before ''R/R&D budgets'' was corrected in section 2(b), which identifies the source of funds for the program.

Section 3 contains definitions of terms that appear throughout the Policy Directive. SBA made an editorial revision to the definition of ''Awardee'' in section 3(e). SBA revised the word ''receiving'' to ''that receives.''

Section 4(b)(1), which identifies the objective and nature of a Phase II award, includes a statement regarding the eligibility of successor in interest firms for SBIR awards. Because this statement pertains more generally to eligibility for all SBIR awards, it was removed from section 4(b)(1) and added to section 6(a) which addresses program eligibility requirements.

In Section 6, SBA removed the reference to the STTR program regarding the option to make awards to small businesses that are majority owned by multiple venture capital operating companies, hedge funds or private equity firms. When SBA issued its final size regulations on December 27, 2012 (77 FR 76215), it reviewed this issue and determined that such businesses may not participate in the STTR program. Additionally, SBA added the language previously found at section 4(b)(1) regarding successor in interest firms to section 6(a)(5), because section 6(a) addresses general program eligibility. Sections 6(a)(2) through 6(a)(6) were reorganized and renumbered in order to increase readability.

Section 7 addresses issues related to program funding processes. SBA revised the language in paragraph 7(d) to clarify that while duplicate or similar proposals may be submitted in response to apparently similar solicitation topics, essentially equivalent work may not be funded. In addition, SBA revised paragraph (h)(1), which says that funding agreement modifications should be kept to a minimum, to address only modifications that increase the dollar amount of awards. Paragraph (h)(1) also referred to modifications of periods of performance and scope of work. SBA clarified section 7(h)(1) to specify that the concern regarding the number of modifications made to an award pertains only to changes that increase the dollar amount of awards.

Section 8 of the Directive addresses the terms of agreement under SBIR awards. SBA clarified section 8(a) by removing language stating that agencies should discourage SBCs from submitting proprietary information and revised section 8(d) to clarify that the continued use of agency-owned property applies to property acquired by the awardee under the contract.

In response to concerns regarding the cost and accountability of the continuing study by the National Academy of Sciences, SBA modified section 9(h) to clarify that the agreement required between the agencies and the National Academy of Sciences must be made in consultation with the SBA and must comprehensively address the scope and content of the work to be performed.

Section 10(h) explains the process for agencies to submit their SBIR program annual reports to SBA. Paragraph (h)(4) contains a list of information that must be included in each agency's annual report. SBA clarified section 10(h)(4)(xi) to note that agencies must report all instances in which an agency pursued R/R&D, services, production, or any combination thereof of a technology developed under an SBIR award with an entity other than that SBIR awardee.

Section 10(j) contains information on the other reporting requirements for

SBIR participating agencies. Section 10(j)(2) discusses a system that will list any individual or small business concern that received an SBIR award and that has been convicted of a fraud-related crime involving SBIR funds or found civilly liable for a fraud-related violation involving SBIR funds. SBA clarified this section to note that SBA will list those individuals and small business concerns of which SBA has been made aware.

Section 12(b) addresses the Commercialization Readiness Program at the Department of Defense (DoD). SBA clarified the source of funding for this program by removing the sentence in paragraph (b)(4)(ii) stating that funds for the program would come from the 3% administrative set-aside, and by clarifying that the funds shall not be subject to the limitations on the use of funds in section 9(e)(3). In addition, in section 12(b)(6)(iii)(C), SBA clarified that the DoD must include, along with its description of the incentives used for this program, information on measures taken to ensure that such incentives do not shift the focus of the SBIR Phase II awards away from the relatively high-risk innovation projects they are intended to promote.

Section 12(b)(5) addresses DoD's Commercialization Readiness Program. The Policy Directive states that DoD may establish transition goals and reporting requirements for awards less than $1,000,000,000. The amount listed in section 12(b)(5) contained a typographical error, which was corrected to $100,000,000.

Appendix I provides instructions for the preparation of program solicitations. In Appendix I, SBA revised the certification check box regarding notification if work is subsequently funded by another Federal agency to clarify that it pertains to work funded and completed under the award rather than to the work proposed for the award.

The updated SBIR Policy Directive, incorporating all changes noted here, will be posted on *www.sbir.gov*.

Notice of Amendments to Final Policy Directive; Small Business Innovation Research Program

To: The Small Business Innovation Research Program Managers.

Subject: Amendments to SBIR Policy Directive Published on August 6, 2012 at 77 FR 46806.

1. *Purpose.* The purpose of this notice is to inform SBIR agencies of amendments made to the recently published SBIR Policy Directive.

2. *Authority.* Section 9(j)(3) of the Small Business Act (15 U.S.C. 638(j)) requires the Administrator of the U.S. Small Business Administration (SBA) to issue an SBIR Program Policy Directive for the general conduct of the SBIR Program.

3. *Procurement Regulations.* It is recognized that the Federal Acquisition Regulations and agency supplemental regulations may need to be modified to conform to the requirements of the final Policy Directive. SBA's Administrator or designee must review and concur with any regulatory provisions that pertain to areas of SBA responsibility. SBA's Office of Innovation coordinates such regulatory actions.

4. *Personnel Concerned.* This Policy Directive serves as guidance for all federal government personnel who are involved in the administration of the SBIR Program, issuance and management of Funding Agreements or contracts pursuant to the SBIR Program, and the establishment of goals for small business concerns in research or research and development acquisition or grants.

5. *Originator.* SBA's Office of Innovation and Technology.

6. *Date.* The policy directive is effective on January 8, 2014.

Authorized by:

Dated: December 26, 2013.

Pravina Raghavan,

Deputy Associate Administrator, Office of Investment and Innovation Small Business Administration.

Dated: December 26, 2013.

Jeanne Hulit,

Acting Administrator.

SBA amends the SBIR Policy Directive as follows:

1. Amend section 2(b) by adding the term ''extramural'' before ''R/R&D budgets'' each place it appears.

2. Revise section 3(e) to read as follows:

(e) *Awardee.* The organizational entity that receives an SBIR Phase I, Phase II, or Phase III award.

3. Revise section 4(a)(3) to read as follows:

(3) *Agency benchmarks for progress towards commercialization.* Each agency must determine whether an applicant for a Phase I award that has won multiple prior SBIR awards meets the agency's benchmark requirements for progress towards commercialization before making a new Phase I award to that applicant. For the purpose of this requirement, applicants are assessed using their prior Phase I and Phase II SBIR and STTR awards across all SBIR agencies.

(i) Agencies must apply two benchmark rates addressing an applicant's progress towards commercialization—the Phase II Transition Rate Benchmark and the Commercialization Rate Benchmark.

(A) The Phase II Transition Rate Benchmark sets the minimum required number of Phase II awards the applicant must have received for a given number of Phase I awards received during the specified period. This Transition Rate Benchmark applies only to Phase I applicants that have received more than 20 Phase I awards over the time period used by the agency for the benchmark determination.

(B) The agency Commercialization Rate Benchmark sets the minimum Phase III commercialization results that a Phase I applicant must have realized from its prior Phase II awards in order to be eligible to receive a new Phase I award from that agency. This benchmark requirement applies only to Phase I applicants that have received more than 15 Phase II awards over the time period used by the agency for the benchmark determination.

(ii) *Consequence.* If an awardee fails to meet either of the benchmarks, that awardee is not eligible for an SBIR Phase I award (and any Phase II award issued pursuant to paragraph (b)(1)(ii) below) for a period of one year from the time of the determination.

(iii) *Timing of the determination and consequence period.* The SBIR awardee Phase II transition rates and commercialization rates are calculated using the data in SBA's TechNet database. For the purpose of these benchmark requirements, awardee firms are assessed once a year, on June 1st, using their prior SBIR and STTR awards across all agencies. SBA makes this tabulation of awardee transition rates and commercialization rates available to the agencies. Each SBIR agency uses this tabulation to determine which companies do not meet that agency's benchmark rates and are therefore ineligible to receive new Phase 1 awards from that agency during the one-year period beginning on June 1st and ending on May 31st. SBA notifies these ineligible firms of the determination and the one year restriction on Phase I awards. Agencies must notify SBA of any applications denied because of the failure to meet the benchmarks.

(iv) *Phase II Transition Rate Benchmark.* Each agency must establish an SBA-approved Phase II Transition Rate Benchmark and applicable time period. The benchmark rates and time periods are posted at *www.sbir.gov*. Agencies must seek approval for any subsequent changes from SBA.

(A) The agency Phase II Transition Rate Benchmark establishes the number of Phase II awards a small business

concern must have received for a given number of Phase I awards received over the past 5, 10 or 15 fiscal years, excluding the most recently completed fiscal year. Each agency selects both the rate to be applied and the length of time that the agency will use to evaluate whether a small business concern has met the Transition Rate Benchmark. The period over which Phase I awards are counted excludes the most recently completed fiscal year. The time period over which Phase II awards are counted includes the most recently completed fiscal year and excludes the first year of the time period evaluated for Phase I awards.

Example: On August 1, 2014, an SBC submits an application to an agency using a Transition Rate Benchmark of 0.25 and a 5-year time period. The June 1, 2014 TechNet Company Registry tabulation shows that the SBC received 24 Phase I awards during FY08–FY12. Since this SBC has received 20 or more Phase I awards during the 5-year period, the SBC is required to meet the Transition Rate Benchmark. The SBC received 8 Phase II awards in FY09–FY13 and therefore has a 5-year Phase II transition rate of 8/24 or 0.33 (# of Phase II awards in FY09–FY13/# of Phase I awards in FY08–FY12). Because the SBC meets or exceeds the agency Transition Rate Benchmark, it is considered for award through the usual proposal evaluation process.

Example 2: On September 1, 2014, an SBC is interested in applying for a Phase I award, knows it has received a number of Phase I awards in recent years, but is unsure if it is meeting the required Phase II transition rate. The company official logs onto the Company Registry at SBIR.gov to check its status and sees a flag saying it did not meet the required benchmark transition rate of 0.25 on June 1, 2014 and is therefore ineligible for a Phase I award through May 31, 2015. The company checks its records and sees that it received 30 Phase I awards during FY08–FY12 and 6 Phase II awards during FY09–FY13. Its transition rate is therefore 6/30 or 0.20 which is under the required rate of 0.25. The SBC does not apply for a new Phase I award through May 31, 2015 because it knows its application would be rejected.

Example 3: On September 1, 2014, an SBC official interested in applying for a Phase I award logs onto the Company Registry at SBIR.gov and sees the flag saying it did not meet the required benchmark transition rate of 0.25 on June 1, 2014 and is not eligible for a Phase I award through May 31, 2015. However, when the company checks its own records, it sees that it received 8 Phase II awards during FY09–FY13, not the 6 awards showing on the Web site. Its transition rate is therefore 8/30 or 0.26 which is above the required rate of 0.25. The company official therefore goes to SBIR.gov, clicks on the ''Dispute Transition Rate'' button, and enters the information about the discrepancy. SBA uses the information provided by the company and, working with the relevant agencies, identifies that two Phase II awards from FY09 had been inadvertently omitted. SBA updates and corrects the database and informs the firm that it is indeed eligible to receive SBIR Phase I awards.

(B) An SBC that has received more than 20 Phase I awards in the relevant time period can view its Phase II transition rate on the Company Registry page at SBIR.gov. Generally, the award data used to calculate an SBC's transition rate will be complete by the end of March each year. An SBC may view its SBIR/STTR award information on the Company Registry at any time. If an awardee believes its Phase II transition rate is calculated using incomplete award information, the awardee may dispute the rate using the link provided on the Company Registry, provide the additional award information, and request a reconsideration of its transition rate. Requests for reconsideration of a firm's transition rate received by SBA from April 1st through April 30th of each year will be considered for the June 1st transition rate assessment.

(C) Agencies must set the Phase II Transition Rate Benchmark as appropriate for their programs and industry sectors. When setting the Transition Rate Benchmark, agencies should consider that Phase I is designed and intended to explore high-risk, early-stage research ideas and, as a result, not all Phase I awards are expected to result in a Phase II award.

(v) *Commercialization Rate Benchmark.* By October 1, 2013, each agency will establish an SBA-approved Commercialization Rate Benchmark that establishes the level of Phase III commercialization results an SBC must have received from work it performed under prior Phase II awards, over the prior 5, 10 or 15 fiscal years, excluding the most recently completed two fiscal years. Agencies may define this benchmark:

(A) in financial terms, such as by using the ratio of the dollar value of revenues and additional investment resulting from prior Phase II awards relative to the dollar value of the Phase II awards received over the time period;

(B) in terms of the share of Phase II awards received over the time period that have resulted in the introduction of a product to market; or

(C) by other means such as using a commercialization scoring system that rates awardees on their past commercialization success.

(vi) Agencies must submit their Transition Rate Benchmark, Commercialization Rate Benchmark, and time periods to SBA for approval. SBA will publish the benchmarks and time periods, seek public comment, and maintain a table of the current requirements on *www.sbir.gov.* The benchmarks and time periods become effective when SBA posts the approved measures on *www.sbir.gov.* Agencies must submit any changes to the benchmarks or time periods to SBA for prior approval.

(vii) SBA maintains a system that records all Phase I, Phase II and Government Phase III awards, and other commercialization information; and calculates the Phase II transition rates for all Phase I awardees and the commercialization rates for all Phase II awardees.

(viii) If an applicant fails to meet an agency's benchmark, its name will appear on the list of companies made available to the agencies on June 1 of each year. An agency may not make a Phase I award to an applicant that does not meet the agency's benchmark.

(ix) If an awardee believes its determination was made in error, it may provide SBA with the pertinent award information and request a reassessment. To do so, awardees may use the link on the Company Registry at *www.sbir.gov*.

4. Amend section 4(b) by revising paragraph (b)(1) by moving language to 6(a)(4), renumbering paragraph (b)(6) as (b)(8), and inserting paragraphs (b)(6) and (b)(7) to read as follows:

(b) *Phase II.*

(1) The object of Phase II is to continue the R/R&D effort from the completed Phase I. Unless an exception set forth in paragraphs (i) or (ii) below applies, only SBIR Phase I awardees are eligible to participate in Phase II.

(i) A Federal agency may issue an SBIR Phase II award to an STTR Phase I awardee to further develop the work performed under the STTR Phase I award. The agency must base its decision upon the results of work performed under the Phase I award and the scientific and technical merit, and commercial potential of the Phase II proposal. The STTR Phase I awardee must meet the eligibility and program requirements of the SBIR Program in order to receive the SBIR Phase II award.

(ii) During fiscal years (FY) 2012 through 2017, the National Institutes of Health (NIH), Department of Defense (DoD) and the Department of Education (DoEd) may issue a Phase II award to a small business concern that did not receive a Phase I award for that R/R&D. Prior to such an award, the heads of those agencies, or designees, must issue a written determination that the small business has demonstrated the scientific and technical merit and feasibility of the ideas that appear to have commercial potential. The determination must be

submitted to SBA prior to issuing the Phase II award.

. . . [paragraphs (2) through (4) are unchanged] . . .

(5) A Phase II awardee may receive one additional, sequential Phase II award to continue the work of an initial Phase II award. The additional, sequential Phase II award has the same guideline amounts and limits as an initial Phase II award.

(6) Agencies may offer special SBIR awards, such as Phase IIB awards, that supplement or extend Phase II awards. For example, some agencies administer Phase IIB awards that differ from the base Phase II in that they require third party matching of the SBIR funds. Each such supplemental award must be linked to a base Phase II award (the initial Phase II, or the second sequential Phase II award). Any SBIR funds used for such special or supplementary awards are aggregated with the amount of the base Phase II to determine the size of that Phase II award. Therefore, while there is no limit on the number of such special/supplementary awards, there is a limit on the total amount of SBIR funds that can be administered through them—the amounts of these awards count towards the size of the initial Phase II or the sequential Phase II, each of which has a guideline amount of $1 million and a limit of $1.5 million. (Note that Phase IIB awards under the NIH SBIR program are administered as second, sequential Phase II awards, not supplemental awards. As such, they are base Phase II awards and subject to the Phase II guideline amounts and limits of $1 million and $1.5 million).

(7) A concern that has received a Phase I award from an agency may receive a subsequent Phase II award from another agency if each agency makes a written determination that the topics of the relevant awards are the same and both agencies report the awards to the SBA including a reference to the related Phase I award and initial Phase II award if applicable.

(8) Agencies may issue Phase II awards for testing and evaluation of products, services, or technologies for use in technical or weapons systems.

5. Revise section 6(a)(2) through § 6(a)(6)to read as follows:

(2) For Phase I, a minimum of two-thirds of the research or analytical effort must be performed by the awardee. For Phase II, a minimum of one-half of the research or analytical effort must be performed by the awardee. Occasionally, deviations from these requirements may occur, and must be approved in writing by the funding agreement officer after consultation with the agency SBIR Program Manager/Coordinator. An agency can measure this research or analytical effort using the total contract dollars or labor hours, and must explain to the small business in the solicitation how it will be measured.

(3) For both Phase I and Phase II, the primary employment of the principal investigator must be with the SBC at the time of award and during the conduct of the proposed project. Primary employment means that more than one-half of the principal investigator's time is spent in the employ of the SBC. This precludes full-time employment with another organization. Occasionally, deviations from this requirement may occur, and must be approved in writing by the funding agreement officer after consultation with the agency SBIR Program Manager/Coordinator. Further, an SBC may replace the principal investigator on an SBIR Phase I or Phase II award, subject to approval in writing by the funding agreement officer. For purposes of the SBIR Program, personnel obtained through a Professional Employer Organization or other similar personnel leasing company may be considered employees of the awardee. This is consistent with SBA's size regulations, 13 CFR 121.106—Small Business Size Regulations.

(4) For both Phase I and Phase II, the R/R&D work must be performed in the United States. However, based on a rare and unique circumstance, agencies may approve a particular portion of the R/R&D work to be performed or obtained in a country outside of the United States, for example, if a supply or material or other item or project requirement is not available in the United States. The funding agreement officer must approve each such specific condition in writing.

(5) An SBIR awardee may include, and SBIR work may be performed by, those identified via a ''novated'' or ''successor in interest'' or similarly-revised funding agreement, or those that have reorganized with the same key staff, regardless of whether they have been assigned a different tax identification number. Agencies may require the original awardee to relinquish its rights and interests in an SBIR project in favor of another applicant as a condition for that applicant's eligibility to participate in the SBIR Program for that project.

(6) NIH, Department of Energy and National Science Foundation may award not more than 25% of the agency's SBIR funds to SBCs that are owned in majority part by multiple venture capital operating companies, hedge funds, or private equity firms through competitive, merit-based procedures that are open to all eligible small business concerns. All other SBIR agencies may award not more than 15% of the agency's SBIR funds to such SBCs. SBIR agencies may or may not choose to utilize this funding option. A table listing the agencies that are currently using this authority can be found at *www.SBIR.gov.* This authority is set forth in 13 CFR 121.701 through 121.705.

(i) Before permitting participation in the SBIR program by SBCs that are owned in majority part by multiple venture capital operating companies, hedge funds, or private equity firms, the SBIR agency must submit a written determination to SBA, the Senate Committee on Small Business and Entrepreneurship, the House Committee on Small Business and the House Committee on Science, Space, and Technology at least 30 calendar days before it begins making awards to such SBCs. The determination must be made by the head of the Federal agency or designee and explain how awards to such SBCs in the SBIR program will:

(A) induce additional venture capital, hedge fund, or private equity firm funding of small business innovations;

(B) substantially contribute to the mission of the Federal agency;

(C) address a demonstrated need for public research; and

(D) otherwise fulfill the capital needs of small business concerns for additional financing for SBIR projects.

(ii) The SBC that is majority-owned by multiple venture capital operating companies, hedge funds, or private equity firms must register with SBA in the Company Registry Database, at *www.SBIR.gov*, prior to the date it submits an application for an SBIR award.

(iii) The SBC that is majority-owned by multiple venture capital operating companies, hedge funds, or private equity firms must submit a certification with its proposal stating, among other things, that it has registered with SBA.

(iv) Any agency that makes an award under this paragraph during a fiscal year shall collect and submit to SBA data relating to the number and dollar amount of Phase I awards, Phase II awards, and any other category of awards by the Federal agency under the SBIR program during that fiscal year. See section10 of this directive for the specific reporting requirements.

(v) If an agency awards more than the percentage of the funds authorized under section 6(a)(2) of the Policy Directive, the agency shall transfer from its non-SBIR and non-STTR R&D funds to the agency's SBIR funds any amount

that is in excess of the authorized amount. The agency must transfer the funds not later than 180 days after the date on which the Federal agency made the award that exceeded the authorized amount.

(vi) If a Federal agency makes an award under a solicitation more than 9 months after the date on which the period for submitting applications under the solicitation ends, a Covered Small Business Concern is eligible to receive the award, without regard to whether it meets the eligibility requirements of the program for a SBC that is majority-owned by multiple venture capital operating companies, hedge funds, or private equity firms, if the Covered Small Business Concern meets all other requirements for such an award. In addition, the agency must transfer from its non-SBIR and non-STTR R&D funds to the agency's SBIR funds any amount that is so awarded to a Covered Small Business Concern. The funds must be transferred not later than 90 days after the date on which the Federal agency makes the award.

6. Revise section 7(d) to read as follows:

(d) *Essentially Equivalent Work.* SBIR participants often submit duplicate or similar proposals to more than one soliciting agency when the announcement or solicitation appears to involve similar topics or requirements. However, ''essentially equivalent work'' must not be funded in the SBIR or other Federal programs, unless an exception to this rule applies. Agencies must verify with the applicant that this is the case by requiring them to certify at the time of award and during the lifecycle of the award that they do not have essentially equivalent work funded by another Federal agency.

7. Revise section 7(h)(1) to read as follows:

(h) *Periods of Performance and Extensions.*

(1) In keeping with the legislative intent to make a large number of relatively small awards, modification of funding agreements to increase the dollar amount should be kept to a minimum, except for options in original Phase I or II awards.

8. Revise section 8(a) to read as follows:

(a) *Proprietary Information Contained in Proposals.* The standardized SBIR Program solicitation will include provisions requiring the confidential treatment of any proprietary information to the extent permitted by law. The solicitation will require that all proprietary information be identified clearly and marked with a prescribed legend. Agencies may elect to require SBCs to limit proprietary information to that essential to the proposal and to have such information submitted on a separate page or pages keyed to the text. The Government, except for proposal review purposes, protects all proprietary information, regardless of type, submitted in a contract proposal or grant application for a funding agreement under the SBIR Program, from disclosure.

9. Revise section 8(d) to read as follows:

(d) *Continued Use of Government Equipment.* Agencies must allow an SBIR awardee participating in the third phase of the SBIR Program continued use, as a directed bailment, of any property transferred by the agency to the Phase II awardee or acquired by the awardee for the purpose of fulfilling the contract. The Phase II awardee may use the property for a period of not less than 2 years, beginning on the initial date of the concern's participation in the third phase of the SBIR Program.

10. Revise section 9(h) to read as follows:

(h) *National Academy of Sciences Report.* The National Academy of Sciences (NAS) will conduct a study and issue reports on the SBIR and STTR programs.

(1) Prior to and during the period of study, and to ensure that the concerns of small business are appropriately considered, NAS shall consult with and consider the views of SBA's Office of Investment and Innovation and the Office of Advocacy and other interested parties, including entities, organizations, and individuals actively engaged in enhancing or developing the technological capabilities of small business concerns.

(2) The head of each agency with a budget of more than $50,000,000 for its SBIR Program for fiscal year 1999 shall, in consultation with SBA, and not later than 6 months after December 31, 2011, cooperatively enter into an agreement with NAS regarding the content and performance of the study. SBA and the agencies will work with the Interagency Policy Committee in determining the parameters of the study, including the specific areas of focus and priorities for the broad topics required by statute. The agreement with NAS must set forth these parameters, specific areas of focus and priorities, and comprehensively address the scope and content of the work to be performed. This agreement must also require the NAS to ensure there is participation by and consultation with, the small business community, the SBA, and other interested parties as described in paragraph (1).

(3) NAS shall transmit to SBA, heads of agencies entering into an agreement under this section, the Committee on Science, Space and Technology, the Committee on Small Business of the House of Representatives, and to the Committee on Small Business of the Senate a copy of the report, which includes the results and recommendations, not later than 4 years after December 31, 2011, and every subsequent four years.

11. Revise section 10(h)(4)(xi) to read as follows:

(xi) All instances in which an agency pursued R/R&D, services, production, or any combination thereof of a technology developed under an SBIR award with an entity other than that SBIR awardee. *See* section 9(a)(12) for minimum reporting requirements.

12. Revise section 10(j)(2) to read as follows:

(2) The system will include a list of any individual or small business concern that has received an SBIR award and that has been convicted of a fraud-related crime involving SBIR funds or found civilly liable for a fraud-related violation involving SBIR funds, of which SBA has been made aware.

13. Revise section 12(b)(4) to read as follows:

(4) *Funding.*

(i) Beginning with FY 2013 and ending in FY 2015, the Secretary of Defense and each Secretary of a military department is authorized to use its SBIR funds for administration of this program in accordance with the procedures and policies set forth in section 9(e)(3) of this directive.

(ii) In addition, the Secretary of Defense and Secretary of each military department is authorized to use not more than an amount equal to 1% of its SBIR funds available to DoD or the military departments for payment of expenses incurred to administer the Commercialization Program. Such funds—

(A) shall not be subject to the limitations on the use of funds in 9(e)(2) or 9(e)(3) of this directive; and

(B) shall not be used to make Phase III awards.

14. Revise section 12(b)(5) to read as follows:

(5) *Contracts Valued at less than $100,000,000.* For any contract awarded by DoD valued at less than $100,000,000, the Secretary of Defense may:

(i) establish goals for the transition of Phase III technologies in subcontracting plans; and

(ii) require a prime contractor on such a contract to report the number and dollar amount of the contracts entered

into by the prime contractor for Phase III SBIR projects.

15. Revise section 12(b)(6) to read as follows:

(6) The Secretary of Defense shall:

(i) set a goal to increase the number of SBIR Phase II contracts that lead to technology transition into programs of record of fielded systems;

(ii) use incentives in effect as of December 31, 2011 or create new incentives to encourage agency program managers and prime contractors to meet the goal set forth in paragraph (6)(i) above; and

(iii) submit the following to SBA, as part of the annual report:

(A) the number and percentage of Phase II SBIR contracts awarded by DoD that led to technology transition into programs of record or fielded systems;

(B) information on the status of each project that received funding through the Commercialization Program and the efforts to transition these projects into programs of record or fielded systems; and

(C) a description of each incentive that has been used by DoD, the effectiveness of the incentive with respect to meeting DoD's goal to increase the number of SBIR Phase II contracts that lead to technology transition into programs of record of fielded systems, and measures taken to ensure that such incentives do not act to shift the focus of SBIR Phase II awards away from relatively high-risk innovation projects.

16. Revise paragraph 1(a) of the Appendix I: Instructions for Preparation of SBIR Program Solicitation to read as follows:

(a) Summarize in narrative form the request for proposals and the objectives of the SBIR Program.

17. In Appendix I, in the SBIR Funding Agreement Certification and the SBIR Funding Agreement Certification—Life Cycle Certification, revise the checkbox addressing potential duplicative funding to read as follows:

It will notify the Federal agency immediately if all or a portion of the work authorized and funded under this award is subsequently funded by another Federal agency.

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SMALL BUSINESS ADMINISTRATION

13 CFR Chapter I

RIN 3245–AF45

Small Business Technology Transfer Program Policy Directive

AGENCY: Small Business Administration.

ACTION: Notice of amendments to final policy directive.

SUMMARY: The U.S. Small Business Administration (SBA) is amending its Small Business Technology Transfer (STTR) Program Policy Directive in response to public comments SBA received on the final STTR and Small Business Innovation Research (SBIR) Policy Directives, published on August 6, 2012. SBA is also making several minor clarifying changes to ensure that the STTR participants clearly understand certain program requirements. Additionally, the changes to the STTR Policy Directive are made to maintain concordance with the SBIR program.

DATES: These amendments to the STTR Policy Directive are effective January 8, 2014.

FOR FURTHER INFORMATION CONTACT: Edsel Brown, Assistant Director, Office of Innovation, at (202) 401–6365 or *technet@sba.gov.*

SUPPLEMENTARY INFORMATION: On December 31, 2011, the President signed into law the National Defense Authorization Act for Fiscal Year 2012 (Defense Reauthorization Act), Public Law 112–81, 125–Stat. 1298. Section 5001, Division E of the Defense Reauthorization Act contains the SBIR/STTR Reauthorization Act of 2011 (Reauthorization Act), which amended the Small Business Act and made several amendments to the STTR Program. The Reauthorization Act required SBA to issue amendments to the STTR Policy Directive and publish the amendments in the **Federal Register** within 180 days of when the Reauthorization Act was passed.

On August 6, 2012, SBA published a final STTR Policy Directive implementing the various provisions of the Reauthorization Act at 77 FR 46855. The directive made several key changes to the STTR Program relating to eligibility, the award process, program administration, and fraud, waste and abuse. Although the STTR Policy Directive is intended for use by the STTR participating agencies, SBA believed that public input on the directive from all parties involved in the program would be invaluable. Therefore, SBA sought public comments on the final directive, and stated that it may amend the directive in response to these comments at a later time.

Response to Comments

In response to this request, SBA received comments on various parts of the directive. If SBA received comments on a section of the SBIR Policy Directive that also appears in the STTR Policy Directive, SBA clarified the relevant sections in both the SBIR and STTR Policy Directives, when appropriate, in order to maintain concordance between the programs. Several comments recommended that SBA strengthen and clarify the Policy Directive language with regard to SBIR/STTR data rights and the obligation of federal agencies to give a preference in contracting to SBIR/STTR awardees for follow-on Phase III work. SBA agrees that these areas of SBIR/STTR policy are vital to the programs and require clarification and improvement. The SBA continues to evaluate these issues and will address them in a subsequent Policy Directive revision.

Section 4(a)(3) ''Agency benchmarks for progress towards commercialization'' sets forth the program policy regarding an eligibility requirement for Phase I awards. SBA received comments requesting clarification of the time periods used to calculate the transition rate and commercialization rate benchmark requirements. Commenters also requested clarification about how agencies determine which firms must comply with the transition rate and commercialization rate benchmarks. In response to these comments, SBA revised and reorganized section 4(a)(3) to clarify several procedural elements about the benchmark determinations and enhance its readability.

Section 4(a)(3) clarifies the time periods used to calculate awardee rates of transition from Phase I to Phase II and provides two examples of the calculation. While the rate is calculated using Phase I awards received in the most recent 5, 10, or 15-year period (agencies choose which period they use), excluding the most recently completed fiscal year; the period used when counting the Phase II awards is lagged one year. That is, when calculating the number of Phase I awards received over a particular time period, the time period evaluated does not include the most recently completed fiscal year; however, when calculating the number of Phase II awards received, the time period evaluated does include the most recently completed fiscal year but does not include the first year of the period evaluated for Phase I awards

received. The period used to calculate Phase II awards is lagged one-year because it is unlikely that a new Phase I would transition to a Phase II within the same year. SBA also clarified that the Phase II transition benchmark requirement applies only to awardees that have received more than 20 Phase I awards over the applicable time period and that the commercialization benchmark applies only to firms that received more than 15 Phase II awards over the applicable time period.

Based on additional input from the agencies participating in the SBIR and STTR programs, SBA also revised several procedural elements of the Phase II transition benchmark requirement in section 4(a)(3) to simplify the process for small businesses and reduce the administrative burden on the agencies. Specifically, in section 4(a)(3)(iii), SBA changed the start date for the one-year ineligibility period for firms that do not meet the benchmarks. The date was changed from the date of application submission to June 1st of each year. SBA made this change for several reasons: (1) It is a clearly defined period for affected small businesses; (2) to provide sufficient time for agencies to enter fully verified award data from the prior fiscal year into the TechNet database; and (3) to eliminate the need for agencies to track multiple periods of ineligibility. SBA will use its TechNet Data system to generate the list of companies that do not meet agency Phase II transition benchmarks and provide this list to the agencies each year on June 1. Finally, SBA also added a procedure to notify awardee firms if they are on the ineligible list and to enable firms to provide feedback directly to SBA if they believe their rate was calculated using incomplete award information.

Some respondents asked if the provision in section 4(b)(5) allowing one Sequential Phase II award included supplementary awards such as Phase 2.5 or Phase IIb awards in the definition of a Phase II award. SBA relocated the language at section 4(b)(6) to new section 4(b)(8) and added new section 4(b)(6) to clarify SBA's policy on supplemental phase II awards. Section 4(b)(6) now clarifies how Phase II award amounts are calculated when supplemental awards are issued. Furthermore, section 4(b)(6) specifies that all supplementary awards, such as a Phase IIb, must be linked to either an initial Phase II or a sequential Phase II award and is added to the amount of that award for the purpose of determining the size of the Phase II award. This means that all supplementary Phase II awards including options, enhancements, administrative supplements, and Phase IIb-type programs are considered as part of the initial Phase II or sequential Phase II from which they derive and are therefore subject to the Phase II per-award guideline amount of $1 million and limit of $1.5 million.

SBA repeated the language in section 9(d)(2) in new section 4(b)(7), which explains how a Phase I awardee may receive an award from one agency and also may receive a subsequent Phase II award from another agency. SBA also clarified in section 4(b)(7) that the same process applies to a second, sequential Phase II award that follows an initial Phase II award from a different agency. This policy is relevant to interagency actions, which are found at section 9 of the Policy Directive, and also to Phase II awards, which is found at section 4 of the Policy Directive.

The reauthorization legislation included a provision giving SBIR agencies the option to use a portion of their program funds to make awards to small businesses that are majority owned by multiple venture capital operating companies, hedge funds or private equity firms. SBA applied this option to the STTR program in section 6(a)(2) of the Policy Directive. SBA received comments that the option should not apply to the STTR program because the reauthorization legislation did not extend the participation of these firms to the STTR program. SBA agrees with commenter. When SBA issued the final regulations amending Title 13, Part 121, Small Business Size Regulations, Small Business Innovation Research (SBIR) Program and Small Business Technology Transfer (STTR) Program, on December 27, 2012 (77 FR 76215), it reviewed this issue and concluded that such firms may not participate in the STTR program. SBA has removed paragraph (a)(2) from section 6 and all other sections of the directive where this provision was applied, including section 6(b)(1)(i) and the related certification in Appendix I, Instructions for Preparation of STTR Program Solicitation, section 2(b)(i).

SBA received comments concerning section 9 of the Policy Directives that addressed measures to prevent fraud, waste and abuse in the program. The respondents commented that the administrative requirements contained in section 9 may be too stringent and may discourage small businesses from applying. SBA notes that it developed these requirements, including the procedures and requirements for certification, in consultation with the Council of Inspectors General on Integrity and Efficiency. SBA believes that these provisions can help reduce fraud, waste and abuse in the program and does not think these provisions should be changed at this time.

SBA received comments on the Department of Defense's (DoD's) Commercialization Readiness Program, outlined in section 12(b) of the STTR Policy Directive. In response to comments that agency efforts to increase transitions to Phase III could reduce the innovative nature of SBIR awards, SBA has added that when DoD reports on its Phase II insertion incentives, it should note efforts that the agency has made to ensure that such incentives do not act to shift the focus of SBIR and STTR Phase II awards away from relatively high-risk innovation projects. SBA also amended the provisions relating to the use of SBIR funds for the DoD Commercialization Readiness Program, which is funded from SBIR funds, but may benefit both the SBIR and STTR programs. According to section 1615 of the National Defense Authorization Act for Fiscal Year 2013 (NDAA), Public Law 112–239, 126 Stat. 1632, DoD has the authority to use 1% of its SBIR funding for purposes of administering the Commercialization Readiness Program.

A number of comments asked us to change features that, because they are required by statute, we were not able to modify.

Miscellaneous Changes

The inadvertent omission of the term ''extramural'' before ''R/R&D budgets'' was corrected in section 2(b), which identifies the source of funds for the program.

Section 3 contains definitions of terms that appear throughout the Policy Directive. SBA made an editorial revision to the definition of ''Awardee'' in section 3(e). SBA revised the word ''receiving'' to ''that receives.''

Section 4(b)(1), which identifies the objective and nature of a Phase II award, includes a statement regarding the eligibility of successor in interest firms for STTR awards. Because this statement pertains more generally to eligibility for all STTR awards, it was removed from section 4(b)(1) and added to section 6(a) which addresses program eligibility requirements.

Section 6(a) addresses general program eligibility. SBA added the language previously found at section 4(b)(1) regarding successor in interest firms to new section 6(a)(5). Sections 6(a)(3) and (4), renumbered as sections 6(a)(2) and (3), state program requirements regarding the percentage of work performed by the SBC and the

place of employment of the principal investigator, respectively. SBA revised these sections to make a technical clarification that the STTR program does not provide small business concerns the opportunity to request a deviation from these requirements. The provision allowing for deviations in these sections was erroneously added to the STTR Policy Directive that was published in August 2012.

Section 7 addresses issues related to program funding processes. SBA revised the language in paragraph 7(d) to clarify that while duplicate or similar proposals may be submitted in response to apparently similar solicitation topics, essentially equivalent work may not be funded. In addition, SBA revised paragraph (i)(1), which says that funding agreement modifications should be kept to a minimum, to address only modifications that increase the dollar amount of awards. Paragraph (i)(1) also referred to modifications of periods of performance and scope of work. SBA clarified section 7(i)(1) to specify that the concern regarding the number of modifications made to an award pertains only to changes that increase the dollar amount of awards.

Section 8 of the Directive addresses the terms of agreement under STTR awards. SBA clarified section 8(a) by removing language stating that agencies should discourage SBCs from submitting proprietary information and revised section 8(e) to clarify that the continued use of agency-owned property applies to property acquired by the awardee under the contract.

In response to concerns regarding the cost and accountability of the continuing study by the National Academy of Sciences, SBA modified section 9(h) to clarify that the agreement required between the agencies and the National Academy of Sciences must be made in consultation with the SBA and must comprehensively address the scope and content of the work to be performed.

Section 10(h) explains the process for agencies to submit their STTR program annual reports to SBA. Paragraph (h)(4) contains a list of information that must be included in each agency's annual report. SBA clarified section 10(h)(4)(xi) to note that agencies must report all instances in which an agency pursued R/R&D, services, production, or any combination thereof of a technology developed under an STTR award with an entity other than that STTR awardee. SBA removed the unnecessary language, ''and determined that it was not practicable to enter into a follow-on funding agreement with non-STTR funds with that concern,'' because it unintentionally created an additional condition for this reporting requirement.

Section 10(j) contains information on the other reporting requirements for STTR participating agencies. Section 10(j)(2) discusses a system that will list any individual or small business concern that received an STTR award and that has been convicted of a fraud-related crime involving STTR funds or found civilly liable for a fraud-related violation involving STTR funds. SBA clarified this section to note that SBA will list those individuals and small business concerns of which SBA has been made aware.

Section 12(b) addresses the Commercialization Readiness Program at the Department of Defense (DoD). SBA clarified the source of funding for this program by removing the sentence in paragraph (b)(4)(ii) stating that funds for the program would come from the 3% administrative set-aside, and by clarifying that the funds shall not be subject to the limitations on the use of funds in section 9(e)(3). In addition, in section 12(b)(6)(iii)(C), SBA clarified that the DoD must include, along with its description of the incentives used for this program, information on measures taken to ensure that such incentives do not shift the focus of the STTR Phase II awards away from the relatively high-risk innovation projects they are intended to promote.

Section 12(b)(5) addresses DoD's Commercialization Readiness Program. The Policy Directive states that DoD may establish transition goals and reporting requirements for awards less than $1,000,000,000. The amount listed in section 12(b)(5) contained a typographical error, which was corrected to $100,000,000.

Appendix I provides instructions for the preparation of program solicitations. In Appendix I, SBA revised the certification check box regarding notification if work is subsequently funded by another Federal agency to clarify that it pertains to work funded and completed under the award rather than to the work proposed for the award.

The updated STTR Policy Directive, incorporating all changes noted here, will be posted on *www.sbir.gov*.

Notice of Amendments to Final Policy Directive; Small Business Technology Transfer Program

To: The Small Business Technology Transfer Program Managers

Subject: Amendments to STTR Policy Directive Published on August 6, 2012 at 77 FR 46855.

1. *Purpose.* The purpose of this notice is to inform STTR agencies of amendments made to the recently published STTR Policy Directive.

2. *Authority.* Section 9(j)(3) of the Small Business Act (15 U.S.C. 638(j)) requires the Administrator of the U.S. Small Business Administration (SBA) to issue an STTR Program Policy Directive for the general conduct of the STTR Program.

3. *Procurement Regulations.* It is recognized that the Federal Acquisition Regulations and agency supplemental regulations may need to be modified to conform to the requirements of the final Policy Directive. SBA's Administrator or designee must review and concur with any regulatory provisions that pertain to areas of SBA responsibility. SBA's Office of Innovation coordinates such regulatory actions.

4. *Personnel Concerned.* This Policy Directive serves as guidance for all federal government personnel who are involved in the administration of the STTR Program, issuance and management of Funding Agreements or contracts pursuant to the STTR Program, and the establishment of goals for small business concerns in research or research and development acquisition or grants.

5. *Originator.* SBA's Office of Innovation and Technology.

6. *Date.* The policy directive is effective on January 8, 2014.

Dated: December 26, 2013.

Pravina Raghavan,

Deputy Associate Administrator, Office of Investment and Innovation Small Business Administration.

Dated: December 26, 2013.

Jeanne Hulit,

Acting Administrator.

SBA amends the STTR Policy Directive as follows:

1. Amend section 2(b) by adding the term ''extramural'' before ''R/R&D budgets'' each place it appears.

2. Revise section 3(e) to read as follows:

(e) *Awardee.* The organizational entity that receives an STTR Phase I, Phase II, or Phase III award.

3. Revise section 4(a)(3) to read as follows:

(3) *Agency benchmarks for progress towards commercialization.* Each agency must determine whether an applicant for a Phase I award that has won multiple prior STTR awards meets the agency's benchmark requirements for progress towards commercialization before making a new Phase I award to that applicant. For the purpose of this requirement, applicants are assessed using their prior Phase I and Phase II SBIR and STTR awards across all agencies.

(i) Agencies must apply two benchmark rates addressing an applicant's progress towards commercialization—the Phase II Transition Rate Benchmark and the Commercialization Rate Benchmark.

(A) The Phase II Transition Rate Benchmark sets the minimum required number of Phase II awards the applicant must have received for a given number of Phase I awards received during the specified period. This Transition Rate Benchmark applies only to Phase I applicants that have received more than 20 Phase I awards over the time period used by the agency for the benchmark determination.

(B) The agency Commercialization Rate Benchmark sets the minimum Phase III commercialization results that a Phase I applicant must have realized from its prior Phase II awards in order to be eligible to receive a new Phase I award from that agency. This benchmark requirement applies only to Phase I applicants that have received more than 15 Phase II awards over the time period used by the agency for the benchmark determination.

(ii) *Consequence.* If an awardee fails to meet either of the benchmarks, that awardee is not eligible for an STTR Phase I award (and any Phase II award issued pursuant to paragraph (b)(1)(ii) below) for a period of one year from the time of the determination.

(iii) *Timing of the determination and consequence period.* The SBIR/STTR awardee Phase II transition rates and commercialization rates are calculated using the data in SBA's TechNet database. For the purpose of these benchmark requirements, awardee firms are assessed once a year, on June 1st, using their prior SBIR and STTR awards across all agencies. SBA makes this tabulation of awardee transition rates and commercialization rates available to the agencies. Each SBIR/STTR agency uses this tabulation to determine which companies do not meet that agency's benchmark rates and are therefore ineligible to receive new Phase 1 awards from that agency during the one-year period beginning on June 1st and ending on May 31st. SBA notifies these ineligible firms of the determination and the one year restriction on Phase I awards. Agencies must notify SBA of any applications denied because of the failure to meet the benchmarks.

(iv) *Phase II Transition Rate Benchmark.* Each agency must establish an SBA-approved Phase II Transition Rate Benchmark and applicable time period. The benchmark rates and time periods are posted at *www.sbir.gov*. Agencies must seek approval for any subsequent changes from SBA.

(A) The agency Phase II Transition Rate Benchmark establishes the number of Phase II awards a small business concern must have received for a given number of Phase I awards received over the past 5, 10 or 15 fiscal years, excluding the most recently completed fiscal year. Each agency selects both the rate to be applied and the length of time that the agency will use to evaluate whether a small business concern has met the Transition Rate Benchmark. The time period over which Phase I awards are counted excludes the most recently completed fiscal year. The time period over which Phase II awards are counted includes the most recently completed fiscal year and excludes the first year of the time period evaluated for Phase I awards.

Example 1: On August 1, 2014, an SBC submits a Phase I application to an agency using a Transition Rate Benchmark of 0.25 and a 5-year time period. The June 1, 2014 TechNet Company Registry tabulation shows that the SBC received 24 Phase I awards during FY08–FY12. Since this SBC has received 20 or more Phase I awards during the 5-year period, the SBC is required to meet the Transition Rate Benchmark. The SBC received 8 Phase II awards in FY09–FY13 and therefore has a 5-year Phase II transition rate of 8/24 or 0.33 (# of Phase II awards in FY09–FY13/# of Phase I awards in FY08–FY12). Because the SBC meets or exceeds the agency Transition Rate Benchmark, it is considered for award through the usual proposal evaluation process.

Example 2: On September 1, 2014, an SBC is interested in applying for a Phase I award, knows it has received a number of Phase I awards in recent years, but is unsure if it is meeting the required Phase II transition rate. The company official logs onto the Company Registry at SBIR.gov to check its status and sees a flag saying it did not meet the required benchmark transition rate of 0.25 on June 1, 2014 and is therefore ineligible for a Phase I award through May 31, 2015. The company checks its records and sees that it received 30 Phase I awards during FY08–FY12 and 6 Phase II awards during FY09–FY13. Its transition rate is therefore 6/30 or 0.20 which is under the required rate of 0.25. The SBC does not apply for a new Phase I award through May 31, 2015 because it knows its application would be rejected.

Example 3: On September 1, 2014, an SBC official interested in applying for a Phase I award logs onto the Company Registry at SBIR.gov and sees the flag saying it did not meet the required benchmark transition rate of 0.25 on June 1, 2014 and is not eligible for a Phase I award through May 31, 2015. However, when the company checks its own records, it sees that it received 8 Phase II awards during FY09–FY13, not the 6 awards showing on the Web site. Its transition rate is therefore 8/30 or 0.26 which is above the required rate of 0.25. The company official therefore goes to SBIR.gov, clicks on the ''Dispute Transition Rate'' button, and enters the information about the discrepancy. SBA uses the information provided by the company and, working with the relevant agencies, identifies that two Phase II awards from FY09 had been inadvertently omitted. SBA updates and corrects the database and informs the firm that it is indeed eligible to receive Phase I awards.

(B) An SBC that has received more than 20 phase I awards in the relevant time period can view its Phase II transition rate on the Company Registry page at SBIR.gov. Generally, the the award data used to calculate an SBC's transition rate will be complete by the end of March each year. An SBC may view its SBIR/STTR award information on the Company Registry at any time. If an awardee believes its Phase II transition rate is calculated using incomplete award information, the awardee may dispute the rate using the link provided on the Company Registry, provide the additional award information, and request a reconsideration of its transition rate. Requests for reconsideration of a firm's transition rate received by SBA from April 1st through April 30th of each year will be considered for the June 1st transition rate assessment.

(C) Agencies must set the Phase II Transition Rate Benchmark as appropriate for their programs and industry sectors. When setting the Transition Rate Benchmark, agencies should consider that Phase I is designed and intended to explore high-risk, early-stage research ideas and, as a result, not all Phase I awards are expected to result in a Phase II award.

(v) *Commercialization Rate Benchmark.* By October 1, 2013, each agency will establish an SBA-approved Commercialization Rate Benchmark that establishes the level of Phase III commercialization results an SBC must have received from work it performed under prior Phase II awards, over the prior 5, 10 or 15 fiscal years, excluding the most recently completed two fiscal years. Agencies may define this benchmark:

(A) in financial terms, such as by using the ratio of the dollar value of revenues and additional investment resulting from prior Phase II awards relative to the dollar value of the Phase II awards received over the time period;

(B) in terms of the share of Phase II awards received over the time period that have resulted in the introduction of a product to market; or

(C) by other means such as using a commercialization scoring system that rates awardees on their past commercialization success.

(vi) Agencies must submit their Transition Rate Benchmark, Commercialization Rate Benchmark, and time periods to SBA for approval.

SBA will publish the benchmarks and time periods, seek public comment, and maintain a table of the current requirements on *www.sbir.gov.* The benchmarks and time periods become effective when SBA posts the approved measures on *www.sbir.gov.* Agencies must submit any changes to the benchmarks or time periods to SBA for prior approval.

(vii) SBA maintains a system that records all Phase I, Phase II and Government Phase III awards, and other commercialization information; and calculates the Phase II transition rates for all Phase I awardees and the commercialization rates for all Phase II awardees.

(viii) If an applicant fails to meet an agency's benchmark, its name will appear on the list of companies made available to the agencies on June 1 of each year. An agency may not make a Phase I award to an applicant that does not meet the agency's benchmark.

(ix) If an awardee believes its determination was made in error, it may provide SBA with the pertinent award information and request a re-assessment. To do so, awardees may use the link on the Company Registry at *www.sbir.gov.*

4. Amend section 4(b) by revising paragraph (b)(1), renumbering paragraph (b)(6) as (b)(8), and inserting paragraphs (b)(6) and (b)(7) to read as follows:

(b) *Phase II.*

(1) The object of Phase II is to continue the R/R&D effort from the completed Phase I. Unless the exception set forth in paragraph (i) below applies, only STTR Phase I awardees are eligible to participate in Phase II.

(i) A Federal agency may issue an STTR Phase II award to an SBIR Phase I awardee to further develop the work performed under the SBIR Phase I award. The agency must base its decision upon the results of work performed under the Phase I award and the scientific and technical merit, and commercial potential of the Phase II proposal. The SBIR Phase I awardee must meet the eligibility and program requirements of the STTR Program in order to receive the STTR Phase II award.

. . . [paragraphs (2) through (4) are unchanged] . . .

(5) A Phase II awardee may receive one additional, sequential Phase II award to continue the work of an initial Phase II award. The additional, sequential Phase II award has the same guideline amounts and limits as an initial Phase II award.

(6) Agencies may offer special STTR awards, such as Phase IIB awards, that supplement or extend Phase II awards. For example, some agencies administer Phase IIB awards that differ from the base Phase II in that they require third party matching of the SBIR funds. Each such supplemental award must be linked to a base Phase II award (the initial Phase II or the second, sequential Phase II award). Any STTR funds used for such special or supplementary awards are aggregated with the amount of the base Phase II to determine the size of that Phase II award. Therefore, while there is no limit on the number of such special/supplementary awards, there is a limit on the total amount of STTR funds that can be administered through them—the amounts of these awards count towards the size of the initial Phase II or the sequential Phase II, each of which has a guideline amount of $1 million and a limit of $1.5 million. (Note that Phase IIB awards under the NIH STTR program are administered as second, sequential Phase II awards, not supplemental awards. As such, they are base Phase II awards and subject to the Phase II guideline amounts and limits of $1 million and $1.5 million).

(7) An STTR Phase II award may be issued by a Federal agency other than the one that made the Phase I award. Prior to award, the head of the Federal agency that awarded the Phase I and the head of the Federal Agency that plans to issue the Phase II award, or designee, must issue a written determination that the topics of the awards are the same. Both agencies must submit the report to the SBA. The same process applies to a second, subsequent Phase II award that follows an initial Phase II award from a different agency.

(8) Agencies may issue Phase II awards for testing and evaluation of products, services, or technologies for use in technical or weapons systems.

5. Remove section 6(a)(2).

6. Redesignate sections 6(a)(3) and (4) as sections 6(a)(2) and (3) and revise to read as follows:

(2) For both Phase I and Phase II, not less than 40 percent of the R/R&D work must be performed by the SBC, and not less than 30 percent of the R/R&D work must be performed by the single, partnering Research Institution. An agency can measure this research or analytical effort using the total contract dollars or labor hours, and must explain to the small business in the solicitation how it will be measured.

(3) For both Phase I and Phase II, the primary employment of the principal investigator must be with the SBC or the research institution at the time of award and during the conduct of the proposed project. Primary employment means that more than one-half of the principal investigator's time is spent in the employ of the SBC or the research institution. This precludes full-time employment with another organization aside from the SBC or the research institution. An SBC may replace the principal investigator on an STTR Phase I or Phase II award, subject to approval in writing by the funding agreement officer. For purposes of the STTR Program, personnel obtained through a Professional Employer Organization or other similar personnel leasing company may be considered employees of the awardee. This is consistent with SBA's size regulations, 13 CFR 121.106—Small Business Size Regulations.

7. Insert new section 6(a)(5) to read as follows:

(5) An STTR awardee may include, and STTR work may be performed by, those identified via a ''novated'' or ''successor in interest'' or similarly-revised funding agreement, or those that have reorganized with the same key staff, regardless of whether they have been assigned a different tax identification number. Agencies may require the original awardee to relinquish its rights and interests in an STTR project in favor of another applicant as a condition for that applicant's eligibility to participate in the STTR Program for that project.

8. Revise section 7(d) to read as follows:

(d) *Essentially Equivalent Work.* STTR participants often submit duplicate or similar proposals to more than one soliciting agency when the announcement or solicitation appears to involve similar topics or requirements. However, ''essentially equivalent work'' must not be funded in the STTR or other Federal programs, unless an exception to this rule applies. Agencies must verify with the applicant that this is the case by requiring them to certify at the time of award and during the lifecycle of the award that they do not have essentially equivalent work funded by another Federal agency.

9. Revise section 7(h)(1) to read as follows:

(h) *Periods of Performance and Extensions.*

(1) In keeping with the legislative intent to make a large number of relatively small awards, modification of funding agreements to increase the dollar amount should be kept to a minimum, except for options in original Phase I or II awards.

10. Revise section 8(a) to read as follows:

(a) *Proprietary Information Contained in Proposals.* The standardized STTR Program solicitation will include provisions requiring the confidential

treatment of any proprietary information to the extent permitted by law. The solicitation will require that all proprietary information be identified clearly and marked with a prescribed legend. Agencies may elect to require SBCs to limit proprietary information to that essential to the proposal and to have such information submitted on a separate page or pages keyed to the text. The Government, except for proposal review purposes, protects all proprietary information, regardless of type, submitted in a contract proposal or grant application for a funding agreement under the STTR Program, from disclosure.

11. Revise section 8(e) to read as follows:

(e) *Continued Use of Government Equipment.* Agencies must allow an STTR awardee participating in the third phase of the STTR Program continued use, as a directed bailment, of any property transferred by the agency to the Phase II awardee or acquired by the awardee for the purpose of fulfilling the contract. The Phase II awardee may use the property for a period of not less than 2 years, beginning on the initial date of the concern's participation in the third phase of the STTR Program.

12. Revise section 9(h) to read as follows:

(h) *National Academy of Sciences Report.* The National Academy of Sciences (NAS) will conduct a study and issue reports on the SBIR and STTR programs.

(1) Prior to and during the period of study, and to ensure that the concerns of small business are appropriately considered, NAS shall consult with and consider the views of SBA's Office of Investment and Innovation and the Office of Advocacy and other interested parties, including entities, organizations, and individuals actively engaged in enhancing or developing the technological capabilities of small business concerns.

(2) The head of each agency with a budget of more than $50,000,000 for its SBIR Program for fiscal year 1999 shall, in consultation with SBA, and not later than 6 months after December 31, 2011, cooperatively enter into an agreement with NAS regarding the content and performance of the study. SBA and the agencies will work with the Interagency Policy Committee in determining the parameters of the study, including the specific areas of focus and priorities for the broad topics required by statute. The agreement with NAS must set forth these parameters, specific areas of focus and priorities, and comprehensively address the scope and content of the work to be performed. This agreement must also require the NAS to ensure there is participation by and consultation with, the small business community, the SBA, and other interested parties as described in paragraph (1).

(3) NAS shall transmit to SBA, heads of agencies entering into an agreement under this section, the Committee on Science, Space and Technology, the Committee on Small Business of the House of Representatives, and to the Committee on Small Business of the Senate a copy of the report, which includes the results and recommendations, not later than 4 years after December 31, 2011, and every subsequent four years.

13. Revise section 10(h)(4)(xi) to read as follows:

(xi) All instances in which an agency pursued R/R&D, services, production, or any combination thereof of a technology developed under an STTR award with an entity other than that STTR awardee. See section 9(a)(12) for minimum reporting requirements.

14. Revise section 10(j)(2) to read as follows:

(2) The system will include a list of any individual or small business concern that has received an STTR award and that has been convicted of a fraud-related crime involving STTR funds or found civilly liable for a fraud-related violation involving STTR funds, of which SBA has been made aware.

15. Revise section 12(b)(4) to read as follows:

(4) *Funding.*

(i) Beginning with FY 2013 and ending in FY 2015, the Secretary of Defense and each Secretary of a military department is authorized to use its SBIR funds for administration of this program in accordance with the procedures and policies set forth in section 9(e)(3) of this directive.

(ii) In addition, the Secretary of Defense and Secretary of each military department is authorized to use not more than an amount equal to 1% of its SBIR funds available to DoD or the military departments for payment of expenses incurred to administer the Commercialization Readiness Program. Such funds—

(A) shall not be subject to the limitations on the use of funds in 9(e)(2) or 9(e)(3) of this directive; and

(B) shall not be used to make Phase III awards.

16. Revise section 12(b)(5) to read as follows:

(5) *Contracts Valued at less than $100,000,000.* For any contract awarded by DoD valued at less than $100,000,000, the Secretary of Defense may:

(i) establish goals for the transition of Phase III technologies in subcontracting plans; and

(ii) require a prime contractor on such a contract to report the number and dollar amount of the contracts entered into by the prime contractor for Phase III STTR projects.

17. Revise section 12(b)(6) to read as follows:

(6) The Secretary of Defense shall:

(i) set a goal to increase the number of STTR Phase II contracts that lead to technology transition into programs of record of fielded systems;

(ii) use incentives in effect as of December 31, 2011 or create new incentives to encourage agency program managers and prime contractors to meet the goal set forth in paragraph (6)(i) above; and

(iii) submit the following to SBA, as part of the annual report:

(A) the number and percentage of Phase II STTR contracts awarded by DoD that led to technology transition into programs of record or fielded systems;

(B) information on the status of each project that received funding through the Commercialization Program and the efforts to transition these projects into programs of record or fielded systems; and

(C) a description of each incentive that has been used by DoD, the effectiveness of the incentive with respect to meeting DoD's goal to increase the number of STTR Phase II contracts that lead to technology transition into programs of record of fielded systems, and measures taken to ensure that such incentives do not act to shift the focus of STTR Phase II awards away from relatively high-risk innovation projects.

18. Revise paragraph 1(a) of the Appendix I: Instructions for Preparation of STTR Program Solicitation to read as follows:

(a) Summarize in narrative form the request for proposals and the objectives of the STTR Program.

19. In Appendix I, in the STTR Funding Agreement Certification and the STTR Funding Agreement Certification—Life Cycle Certification, revise the checkbox addressing potential duplicative funding to read as follows:

€ It will notify the Federal agency immediately if all or a portion of the work authorized and funded under this award is subsequently funded by another Federal agency.

[FR Doc. 2013–31376 Filed 1–7–14; 8:45 am]

BILLING CODE 8025–01–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2013–1004; Directorate Identifier 2013–NE–34–AD; Amendment 39–17719; AD 2013–26–10]

RIN 2120–AA64

Airworthiness Directives; Rolls-Royce plc Turbofan Engines

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Final rule; request for comments.

SUMMARY: We are adopting a new airworthiness directive (AD) for all Rolls-Royce plc (RR) RB211–524G2–19, RB211–524G3–19, RB211–524H–36, and RB211–524H2–19 turbofan engines. This AD requires a one-time reduction in the cyclic life of certain high-pressure (HP) compressor rotor stage 1 and stage 2 discs, and removal of discs that exceed the reduced cycle life. This AD was prompted by a review by RR of the cyclic life of life-limited parts (LLPs) for RB211–524 series engines. We are issuing this AD to prevent the failure of certain LLPs, which could result in uncontained engine damage and damage to the airplane.

DATES: This AD becomes effective January 23, 2014.

We must receive comments on this AD by February 24, 2014.

ADDRESSES: You may send comments by any of the following methods:

- *Federal eRulemaking Portal:* Go to *http://www.regulations.gov* and follow the instructions for sending your comments electronically.
- *Mail:* U.S. Department of Transportation, 1200 New Jersey Avenue SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–0001.
- *Hand Delivery:* Deliver to Mail address above between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.
- *Fax:* 202–493–2251.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov* by searching for and locating Docket No. FAA–2013–1004; or in person at the Docket Operations office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this AD, the mandatory continuing airworthiness information (MCAI), the regulatory evaluation, any comments received, and other information. The street address for the Docket Operations office (phone: 800–647–5527) is the same as the Mail address provided in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Robert Green, Aerospace Engineer, Engine Certification Office, FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7754; fax: 781–238–7199; email: *robert.green@faa.gov.*

SUPPLEMENTARY INFORMATION:

Discussion

The European Aviation Safety Agency (EASA), which is the Technical Agent for the Member States of the European Community, has issued EASA Airworthiness Directive 2013–0246, dated October 10, 2013 (referred to herein after as ''the MCAI''), to correct an unsafe condition for the specified products. The MCAI states:

> Rolls-Royce recently reviewed the cyclic lives of critical parts of the RB211–524 series engines, which has resulted in the identification of a reduced cyclic life limit for certain high-pressure (HP) compressor Rotor Stage 1 and 2 Discs.
>
> Operation of critical parts beyond these reduced cyclic life limits could lead to part failure and consequent release of high-energy debris, possibly resulting in damage to the aeroplane and/or injury to the occupants.

You may obtain further information by examining the MCAI in the AD docket on the Internet at *http://www.regulations.gov* by searching for and locating it in Docket No. FAA–2013–1004.

FAA's Determination and Requirements of This AD

This product has been approved by the aviation authority of the United Kingdom, and is approved for operation in the United States. Pursuant to our bilateral agreement with the European Community, EASA has notified us of the unsafe condition described in the MCAI and service information referenced above. We are issuing this AD because we evaluated all information provided by EASA and determined the unsafe condition exists and is likely to exist or develop on other products of the same type design. This AD requires a one-time reduction in the cyclic life of certain HP compressor stage 1 and stage 2 discs, and removal of discs that exceed the reduced cycle life.

FAA's Determination of the Effective Date

No domestic operators use this product. Therefore, we find that notice and opportunity for prior public comment are unnecessary and that good cause exists for making this amendment effective in less than 30 days.

Comments Invited

This AD is a final rule that involves requirements affecting flight safety, and we did not precede it by notice and opportunity for public comment. We invite you to send any written relevant data, views, or arguments about this AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2013–1004; Directorate Identifier 2013–NE–34–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this AD. We will consider all comments received by the closing date and may amend this AD because of those comments.

We will post all comments we receive, without change, to *http://www.regulations.gov,* including any personal information you provide. We will also post a report summarizing each substantive verbal contact with FAA personnel concerning this AD. Using the search function of the Web site, anyone can find and read the comments in any of our dockets, including, if provided, the name of the individual who sent the comment (or signed the comment on behalf of an association, business, labor union, etc.). You may review the DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477–78).

Costs of Compliance

We estimate that this AD will affect 0 engines installed on airplanes of U.S. registry. We also estimate that it will take about 0 hours per engine to comply with this AD. The average labor rate is $85 per hour. The prorated cost of the parts, adjusted for lost life, is about $15,940 per engine. Based on these figures, we estimate the total cost of this AD to U.S. operators is $0.

Authority for This Rulemaking

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

We are issuing this rulemaking under the authority described in ''Subtitle VII,

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

Regulatory Findings

We determined that this AD will not have federalism implications under Executive Order 13132. This AD will not have a substantial direct effect on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.

For the reasons discussed above, I certify this AD:

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

(2) Is not a ''significant rule'' under the DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979),

(3) Will not affect intrastate aviation in Alaska to the extent that it justifies making a regulatory distinction, and

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

We prepared a regulatory evaluation of the estimated costs to comply with this AD and placed it in the AD docket.

List of Subjects in 14 CFR Part 39

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

Adoption of the Amendment

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

PART 39—AIRWORTHINESS DIRECTIVES

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

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

§ 39.13 [Amended]

■ 2. The FAA amends § 39.13 by adding the following new airworthiness directive (AD):

2013–26–10 Rolls-Royce plc: Amendment 39–17719; Docket No. FAA–2013–1004; Directorate Identifier 2013–NE–34–AD.

(a) Effective Date

This AD is effective January 23, 2014.

(b) Affected ADs

None.

(c) Applicability

This AD applies to all Rolls-Royce plc (RR) RB211–524G2–19, RB211–524G3–19, RB211–524H–36, and RB211–524H2–19 turbofan engines with high-pressure (HP) compressor rotor stage 1 and stage 2 discs, part number LK70608, LK76030, LK86621, UL19877, UL19878, UL19879, or UL24023, installed.

(d) Reason

This AD was prompted by a review by RR of the cyclic life of critical-life-limited parts (LLPs) for RB211–524 series engines. We are issuing this AD to prevent the failure of certain LLPs, which could result in uncontained engine damage and damage to the airplane.

(e) Actions and Compliance

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

(1) Within 30 days after the effective date of this AD, reduce the cyclic life limit for the affected HP compressor rotor stage 1 and stage 2 discs to 7,390 flight cycles (FC).

(2) After the effective date of this AD, remove each affected HP compressor rotor stage 1 and stage 2 disc from service before the part exceeds 7,390 FC.

(3) After the effective date of this AD, do not return to service any engine that has an HP compressor rotor stage 1 and stage 2 disc installed, if the disc has more than 7,390 FC.

(f) Alternative Methods of Compliance (AMOCs)

The Manager, Engine Certification Office, FAA, may approve AMOCs to this AD. Use the procedures found in 14 CFR 39.19 to make your request.

(g) Related Information

(1) For more information about this AD, contact Robert Green, Aerospace Engineer, Engine Certification Office, FAA, Engine & Propeller Directorate, 12 New England Executive Park, Burlington, MA 01803; phone: 781–238–7754; fax: 781–238–7199; email: *robert.green@faa.gov.*

(2) Refer to MCAI European Aviation Safety Agency AD 2013–0246, dated October 10, 2013, for more information. You may examine the MCAI in the AD docket on the Internet at *http://www.regulations.gov* by searching for and locating it in Docket No. FAA–2013–1004.

(h) Material Incorporated by Reference

None.

Issued in Burlington, Massachusetts, on December 23, 2013.

Carlos A. Pestana,

Acting Assistant Directorate Manager, Engine & Propeller Directorate, Aircraft Certification Service.

[FR Doc. 2014–00083 Filed 1–7–14; 8:45 am]

BILLING CODE 4910–13–P

SECURITIES AND EXCHANGE COMMISSION

17 CFR Parts 239, 270, and 274

[Release Nos. 33–9506; IC–30847; File No. S7–7–11]

RIN 3235–AL02

Removal of Certain References to Credit Ratings Under the Investment Company Act

AGENCY: Securities and Exchange Commission.

ACTION: Final rule.

SUMMARY: The Securities and Exchange Commission (''Commission'') is adopting amendments to a rule and three forms under the Investment Company Act of 1940 (''Investment Company Act'') and the Securities Act of 1933 (''Securities Act'') in order to implement a provision of the Dodd-Frank Wall Street Reform and Consumer Protection Act (''Dodd-Frank Act''). Specifically, rule 5b–3 under the Investment Company Act contains a reference to credit ratings in determining when an investment company (''fund'') may treat a repurchase agreement as an acquisition of securities collateralizing the repurchase agreement for certain purposes under the Investment Company Act. The amendments we are adopting today replace this reference to credit ratings with an alternative standard designed to retain a similar degree of credit quality to that in current rule 5b–3. The Commission is also adopting amendments to Forms N–1A, N–2, and N–3 under the Investment Company Act and Securities Act to eliminate the required use of NRSRO credit ratings when a fund chooses to depict its portfolio holdings by credit quality.

DATES: *Effective Date:* February 7, 2014; *Compliance Date:* July 7, 2014.

FOR FURTHER INFORMATION CONTACT: Adam Bolter, Senior Counsel, Thoreau Bartmann, Branch Chief, or C. Hunter Jones, Assistant Director (202) 551–6792, Office of Investment Company Rulemaking, Division of Investment Management, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–8549.

SUPPLEMENTARY INFORMATION: The Commission is adopting amendments to rule 5b–3 [17 CFR 270.5b–3] under the Investment Company Act.[1] The

[1] 15 U.S.C. 80a. Unless otherwise noted, all references to statutory sections are to the Investment Company Act, and all references to rules under the Investment Company Act are to

Commission is also adopting amendments to Forms N–1A [17 CFR 239.15A and 17 CFR 274.11A], N–2 [17 CFR 239.14 and 17 CFR 274.11a–1], and N–3 [17 CFR 239.17a and 17 CFR 274.11b] under the Investment Company Act and the Securities Act.[2]

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I. Background

The first use of a reference to ratings or rating agencies in Commission rules was in 1975, when the Commission adopted the term ''nationally recognized statistical rating organization'' (''NRSRO'') as part of amendments to the net capital rule for broker-dealers, rule 15c3–1 under the Securities Exchange Act of 1934 (''Exchange Act'') (the ''Net Capital Rule'').[3] The Commission eventually included references to credit ratings issued by NRSROs in other rules under the securities laws, including the Investment Company Act.[4] In addition, credit ratings by NRSROs have been used as benchmarks in federal and state legislation, rules administered by other federal agencies, and foreign regulatory schemes.[5] Even prior to the enactment of the Dodd-Frank Act,[6] concerns about the wide-spread use of NRSRO credit ratings in statutes and regulations prompted the Commission to explore whether to eliminate references to credit ratings in Commission rules because of the potential overreliance by investors and, investment advisers and other financial professionals on these ratings, and whether there are practical alternatives to NRSRO credit ratings that could be used as benchmarks in regulations.[7]

Section 939A of the Dodd-Frank Act requires each Federal agency, including the Commission, to ''review any regulation issued by such agency that requires the use of an assessment of the credit-worthiness of a security or money market instrument and any references to or requirements in such regulations regarding credit ratings.'' [8] That section further provides that each such agency shall ''modify any such regulations identified by the review . . . to remove any reference to or requirement of reliance on credit ratings and to substitute in such regulations such standard of credit-worthiness as each respective agency shall determine as appropriate for such regulations.'' [9]

As a step toward implementing these mandates, in March 2011 the Commission proposed to replace references to ratings issued by NRSROs in two Commission rules and four Commission forms under the Investment Company Act, including rule 5b–3 and Forms N–1A, N–2, and N–3.[10] We received 26 comment letters on the proposed rule and form amendments.[11] Several commenters addressed specific provisions of the proposal to amend rule 5b–3 and Forms N–1A, N–2, and N–3, which we discuss in more detail below.

We are adopting, largely as proposed, amendments to rule 5b–3 and Forms N–1A, N–2, and N–3 to implement section 939A of the Dodd-Frank Act and effectuate Congressional intent to reduce reliance on NRSRO credit ratings.[12] As discussed below, the amendments replace a reference to required NRSRO credit ratings in rule 5b–3 for certain securities held by funds as collateral for repurchase agreements with an alternative standard that is designed to retain a similar degree of credit quality. We are also amending Forms N–1A, N–2, and N–3 to eliminate the required use of NRSRO credit ratings by funds that choose to use credit quality categorizations in the required table, chart, or graph of portfolio holdings. Under the amendments, funds that choose to use credit quality to depict portfolio holdings must include a description of how the credit quality of the holding was determined. If a fund chooses to use credit ratings issued by a credit rating agency to depict the credit quality of portfolio holdings, the fund must

Title 17, Part 270 of the Code of Federal Regulations [17 CFR part 270].

[2] 15 U.S.C. 77a.

[3] *See* Adoption of Uniform Net Capital Rule and an Alternative Net Capital Requirement for Certain Brokers and Dealers, Exchange Act Release No. 11497 (June 26, 1975) [40 FR 29795 (July 16, 1975)]; 17 CFR 240.15c3–1. The Net Capital Rule prescribes minimum net capital requirements for broker-dealers and it uses NRSRO credit ratings to determine the amount of the charge to capital a broker-dealer must apply to certain types of debt instruments. *See* 17 CFR 240.15c3–1. The regulatory purpose was to provide a method for determining net capital charges on different grades of debt securities under the Net Capital Rule. *See* 17 CFR 240.15c3–1.

[4] *See, e.g.,* Acquisition and Valuation of Certain Portfolio Instruments by Registered Investment Companies, Investment Company Act Release No. 14983 (Mar. 12, 1986) [51 FR 9773 (Mar. 21, 1986)] (incorporating the concept of NRSROs into the definition of ''eligible security'' in rule 2a–7 (governing money market funds)).

[5] *See, e.g.,* Report to Congress on Credit Ratings, Board of Governors of the Federal Reserve System (July 2011); References to Credit Ratings in FDIC Regulations, Federal Deposit Insurance Corporation (July 2011); and Basel Committee on Banking Supervision, Stocktaking on the use of credit ratings, Joint Forum (June 2009).

[6] *See* Public Law 111–203, 124 Stat. 1376 (2010).

[7] *See infra* section II.A (discussing other Commission actions to remove references to credit ratings from its rules). *See also infra* section II.B (discussing actions of other regulators to remove references to credit ratings from their rules).

[8] Public Law 111–203, sec. 939A(a)(1)–(2). Section 939A of the Dodd-Frank Act applies to all federal agencies.

[9] Public Law 111–203, sec. 939A(b).

[10] *See* References to Credit Ratings in Certain Investment Company Act Rules and Forms, Investment Company Act Release No. 29592 (Mar. 3, 2011) [76 FR 12896 (Mar. 9, 2011)] (''2011 Proposing Release''). Specifically, we proposed to: (i) Remove references to credit ratings in rules 2a–7 and 5b–3 under the Investment Company Act and replace them with alternative standards of creditworthiness; (ii) adopt new rule 6a–5 under the Investment Company Act that would establish a creditworthiness standard to replace the credit rating reference in section 6(a)(5) removed by the Dodd-Frank Act; (iii) eliminate required disclosures of credit ratings in Form N–MFP; and (iv) remove the requirement that credit ratings be used when portraying credit quality in shareholder reports from Forms N–1A, N–2, and N–3. The Commission adopted new rule 6a–5 on November 19, 2012 and noted in its 2013 proposing release for money market reform that the Commission would address references to credit ratings in rule 2a–7 and Form N–MFP in a separate rulemaking. *See* Purchase of Certain Debt Securities by Business and Industrial Development Companies Relying on an Investment Company Act Exemption, Investment Company Act Release No. 30268 (Nov. 19, 2012) [77 FR 70117 (Nov. 23, 2012)]; Money Market Fund Reform; Amendments to Form PF, Investment Company Act Release No. 30551 (June 5, 2013) [78 FR 36834 (June 19, 2013)]. Rule 3a–7 under the Investment Company Act also contains a reference to ratings. In August 2011, in a concept release soliciting comment on the treatment of asset-backed issuers under the Investment Company Act, we sought comment on the role, if any, that credit ratings should continue to play in the context of rule 3a–7. *See* Treatment of Asset-Backed Issuers under the Investment Company Act, Investment Company Act Release No. 29779 (Aug. 31, 2011) [76 FR 55308 (Sept. 7, 2011)] at section III.A.1.

[11] Most of these commenters criticized removing credit ratings from rule 2a–7, but acknowledged that the Commission's proposal was in response to the mandate in the Dodd-Frank Act. The Commission plans to address these comments in a future rulemaking. *See supra* note 10. The comment letters on the 2011 Proposing Release (File No. S7–07–11) are available at *http://www.sec.gov/comments/s7-07-11/s70711.shtml.* In addition, to facilitate public input on the Dodd-Frank Act, we provided a series of email links, organized by topic on our Web site at *http://www.sec.gov/spotlight/regreformcomments.shtml.* The public comments we received on section 939A of the Dodd-Frank Act are available on our Web site at *http://www.sec.gov/comments/df-title-ix/credit-rating-agencies/credit-rating-agencies.shtml.*

[12] *See* Section 939A of the Dodd-Frank Act. Section 939A was intended, at least in part, to address potential over-reliance on NRSRO credit ratings resulting from perceived government-endorsement of NRSROs. *See* Report of the House of Representatives Financial Services Committee to Accompany H.R. 4173, H. Rep. No. 111–517 at 871 (2010).

include a description of how the credit ratings were identified and selected.

In a separate release, the Commission is adopting final amendments to remove references to credit ratings from rules on broker-dealer financial responsibility and confirmations of transactions. These amendments follow the Commission's April 2011 proposed rules in which we proposed to amend rules and one form under the Exchange Act applicable to broker-dealer financial responsibility, distributions of securities, and confirmations of transactions in order to remove references to credit ratings pursuant to section 939A of the Dodd-Frank Act.[13]

II. Prior Actions of the Commission and Other Regulators

As part of our implementation of section 939A, we have reviewed our prior actions and those of other regulators. As discussed below, both the Commission and other regulators have proposed and issued several final rules towards implementation of the mandate under section 939A of the Dodd-Frank Act. In some cases, the references to credit ratings were replaced with an alternative standard of credit quality designed to retain the same degree of credit quality and liquidity as reflected by the use of credit ratings.

A. Prior Commission Actions

The Commission has long been concerned with the use of credit ratings and has taken a variety of actions even before the enactment of the Dodd-Frank Act regarding the use of NRSRO credit ratings in its rules. For example, in 1994, the Commission published a concept release soliciting comment on, among other things, whether the Commission should eliminate references to NRSRO credit ratings from certain rules.[14] The Commission continued to consider the use of credit ratings in its rules, when in 2003, we sought comment on alternative benchmarks that could be used to meet the Commission's regulatory objectives.[15] Finally, in 2008, the Commission proposed amendments to remove references to NRSRO credit ratings from certain of its rules under the Securities Act, Exchange Act, and Investment Company Act.[16] As previously noted, after the enactment of the Dodd-Frank Act, in 2011, the Commission proposed to remove credit ratings references from certain rules and forms under the Investment Company Act.[17] Also in 2011, the Commission separately proposed and adopted amendments removing references to credit ratings in rules and forms under the Securities Act and the Exchange Act related to offerings of securities or issuer disclosure.[18] Generally, in these prior actions, the Commission has proposed or adopted amendments to its rules that seek to retain a similar degree of credit quality to that in the rule being amended by replacing credit ratings references with a two-part standard that includes an assessment of the credit quality and the liquidity of the security, the details of which vary according to the requirements of the particular rule or form.

B. Actions of Other Regulators

A number of other federal agencies have also taken action to implement section 939A of the Dodd-Frank Act, including regulations proposed or adopted by the Commodity Futures Trading Commission (''CFTC''),[19] the Office of the Comptroller of the Currency (''OCC''),[20] the National Credit Union Administration (''NCUA''),[21] the Federal Housing Finance Agency (''FHFA''),[22] the Department of Labor (''DOL''),[23] and jointly by the OCC and Federal Reserve Board (''FRB'').[24] The actions taken by these other regulators were considered in adopting today's amendments.

III. Discussion

A. Rule 5b–3

Rule 5b–3 allows funds to treat the acquisition of a repurchase agreement as an acquisition of securities collateralizing the repurchase agreement for certain diversification and broker-dealer counterparty limit purposes under the Investment Company Act[25] if

[13] *See* Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934, Exchange Act Release No. 64352 (Apr. 27, 2011) [76 FR 26550 (May 6, 2011)] (requesting public comment on proposed amendments to rule 15c3–1 (17 CFR 240.15c3–1), rule 15c3–3 (17 CFR 240.15c3–3), rule 17a–4 (17 CFR 240.17a–4), rules 101 and 102 of Regulation M (17 CFR 242.101 and 242.102), and rule 10b–10 (17 CFR 240.10b–10), and one form—the General Instructions to Form X–17A–5, Part IIB (17 CFR 249.617)—to remove references to credit ratings and, in certain cases, substitute alternative standards of creditworthiness). For purposes of implementing section 939(e) of the Dodd-Frank Act, which eliminated provisions in sections 3(a)(41) and 3(a)(53)(A) of the Exchange Act that referenced NRSRO credit ratings, the Commission also requested comment in the proposing release on potential standards of creditworthiness to replace the credit rating references.

[14] *See* Nationally Recognized Statistical Rating Organizations, Exchange Act Release No. 34616 (Aug. 31, 1994) [59 FR 46314 (Sep. 7, 1994)]; *see also* Capital Requirements for Brokers or Dealers Under the Securities Exchange Act of 1934, Exchange Act Release No. 39457 (Dec. 17, 1997) [62 FR 68018 (Dec. 30, 1997)].

[15] *See* Rating Agencies and the Use of Credit Ratings under the Federal Securities Laws, Exchange Act Release No. 47972 (June 4, 2003) [68 FR 35258 (June 12, 2003)]; *see also* Report on the Role and Function of Credit Rating Agencies in the Operation of the Securities Markets: As Required by Section 702(b) of the Sarbanes-Oxley Act of 2002, Commission (Jan. 2003).

[16] *See, e.g.,* References to Ratings of Nationally Recognized Statistical Rating Organizations, Exchange Act Release No. 58070 (July 1, 2008) [73 FR 40088 (July 11, 2008)]. In October 2009, the Commission adopted several of the 2008 proposed amendments and re-opened for comment the remaining amendments. *See* References to Ratings of Nationally Recognized Statistical Rating Organizations, Exchange Act Release No. 60789 (Oct. 5, 2009) [74 FR 52358 (Oct. 9, 2009)] (adopting release).

[17] *See* 2011 Proposing Release *supra* note 10. One aspect of that rule proposal has already been adopted. New rule 6a–5, adopted by the Commission, replaced a credit rating requirement (removed by Congress as part of the Dodd-Frank Act) applicable to debt securities that certain business and industrial development companies (''BIDCOs'') relying on the Investment Company Act exemption in section 6(a)(5) may invest in. Under new rule 6a–5, a BIDCO that relies on the exemption in section 6(a)(5) may invest in certain debt securities, provided that the BIDCO board determines, at the time of purchase, that the debt security is (1) of no greater than moderate credit risk and (2) is sufficiently liquid. The standard for liquidity is whether the security can be sold at or near its carrying value within a reasonably short period of time. *See* Purchase of Certain Debt Securities by Business and Industrial Development Companies Relying on an Investment Company Act Exemption, Investment Company Act Release No. 30268 (Nov. 19, 2012) [77 FR 70117 (Nov. 23, 2012)].

[18] *See* Security Ratings, Securities Act Release No. 9186 (Feb. 9, 2011) [76 FR 8946 (Feb. 16, 2011)]; *see also* Security Ratings, Securities Act Release No. 9245 (July 27, 2011) [76 FR 46603 (Aug. 3, 2011)] (adopting amendments to rule 134 (17 CFR 230.134), rule 138 (17 CFR 230.138), rule 139 (17 CFR 230.139), rule 168 (17 CFR 230.168), Form S–3 (17 CFR 239.13), Form S–4 (17 CFR 239.25), Form F–3 (17 CFR 239.33), and Form F–4 (17 CFR 230.34) under the Securities Act; rescinding Form F–9 (17 CFR 239.39); adopting amendments to the Securities Act and Exchange Act forms and rules that referred to Form F–9 to eliminate those references; and amending Schedule 14A (17 CFR 240.14a–101) under the Exchange Act).

[19] CFTC, Removing Any Reference to or Reliance on Credit Ratings in Commission Regulations; Proposing Alternatives to the Use of Credit Ratings, 76 FR 44262 (July 25, 2011).

[20] OCC, Alternatives to the Use of External Credit Ratings in the Regulations of the OCC, 77 FR 35253 (June 13, 2012).

[21] NCUA, Alternatives to the Use of Credit Ratings, 77 FR 74103 (Dec. 13, 2012).

[22] FHFA, Removal of References to Credit Ratings in Certain Regulations Governing the Federal Home Loan Banks, 78 FR 30784 (May 23, 2013).

[23] DOL, Proposed Amendments to Class Prohibited Transaction Exemptions to Remove Credit Ratings Pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act, 78 FR 37572 (June 21, 2013).

[24] OCC & FRB, Regulatory Capital Rules: Regulatory Capital, Implementation of Basel III, Capital Adequacy, Transition Provisions, Prompt Corrective Action, Standardized Approach for Risk-weighted Assets, Market Discipline and Disclosure Requirements, Advanced Approaches Risk-Based Capital Rule, and Market Risk Capital Rule, 78 FR 62018 (Oct. 11, 2013).

[25] Section 5(b)(1) of the Investment Company Act limits the amount that a fund that holds itself out as being a diversified investment company may

the obligation of the seller to repurchase the securities from the fund is ''collateralized fully.'' [26] In a typical investment company repurchase agreement, a fund enters into a contract with a broker, dealer, or bank (the ''counterparty'' to the transaction) to purchase securities. The counterparty agrees to repurchase the securities at a specified future date, or on demand, for a price that is sufficient to return to the fund its original purchase price, plus an additional amount representing a return to the fund on its investment. Economically, a repurchase agreement functions as a loan from the fund to the counterparty, in which the securities purchased by the fund serve as collateral for the loan.[27]

Under current requirements, a repurchase agreement is collateralized fully if, among other things, the collateral for the repurchase agreement consists entirely of (i) cash items, (ii) government securities,[28] (iii) securities that at the time the repurchase agreement is entered into are rated in the highest rating category by the ''requisite NRSROs'' [29] or (iv) unrated securities that are of a comparable quality to securities that are rated in the highest rating category by the requisite NRSROs, as determined by the fund's board of directors or its delegate.[30] When the Commission proposed rule 5b-3, we explained that the highest rating category requirement in the definition of fully collateralized was designed to help ensure that the market value of the collateral would remain stable and that the fund could liquidate the collateral quickly in the event of a default by the counterparty. The high quality requirement was also designed to limit a fund's exposure to the ability of the counterparty to maintain sufficient collateral, and reflected the understanding that securities of lower quality may be subject to greater price fluctuation.[31]

Today we are amending rule 5b–3 to eliminate the requirement that collateral other than cash or government securities be rated in the highest category by the requisite NRSROs or be of comparable quality. In place of this requirement, the amended rule requires that collateral other than cash or government securities consist of securities that the fund's board of directors (or its delegate) determines at the time the repurchase agreement is entered into are: (i) Issued by an issuer that has an exceptionally strong capacity to meet its financial obligations on the securities collateralizing the repurchase agreement; and (ii) sufficiently liquid that they can be sold at approximately their carrying value in the ordinary course of business within seven calendar days.[32]

The new credit quality standard we are adopting is designed to retain a degree of credit quality that is similar to the existing standard under rule 5b–3 and consistent with the two-part approach we have taken in establishing credit quality standards to replace credit rating references in other rules under the federal securities laws.[33] We note that our amendment to rule 5b–3 does not affect a money market fund that seeks special treatment of its repurchase agreement holdings under the diversification provisions of rule 2a–7 because in order to obtain such treatment, a money market fund is limited to investing in repurchase agreements collateralized by cash items or government securities (which remain unaffected by our amendments today).[34] We are adopting the liquidity component of the new standard as proposed, but we have revised the credit quality component from what was proposed to address certain commenters' concerns.

We proposed that collateral issuers be required to have the ''highest capacity'' to meet their financial obligations on the collateral securities.[35] Three of the five commenters who addressed the proposed amendments to rule 5b–3 argued that this standard is not consistent with the standard established by the ratings reference in the current rule because the proposed standard does not contemplate any variation in creditworthiness among issuers that meet the highest rating standard.[36] Commenters suggested that short-term collateral securities rated ''A–1+'' or ''A–1'' by Standard & Poor's both would satisfy the rating condition under the current rule, but that only those rated ''A–1+'' would likely have satisfied the credit standard under our proposal.[37] Accordingly, as these commenters recommended, the amended rule requires an issuer to have an ''exceptionally strong'' capacity to meet its financial obligations on the collateral securities.[38] We are adopting this

invest in the securities of any one issuer (other than the U.S. Government). This provision may limit the number and principal amounts of repurchase agreements that a diversified fund may enter into with any one counterparty. Section 12(d)(3) of the Investment Company Act generally prohibits a fund from acquiring an interest in a broker, dealer, or underwriter. Because a repurchase agreement may be considered to be the acquisition of an interest in the counterparty, section 12(d)(3) may limit a fund's ability to enter into repurchase agreements with many of the firms that act as repurchase agreement counterparties. Rule 12d3–1 provides an exemption from the prohibitions of section 12(d)(3) under certain conditions, which exemption a fund may be able to rely on in the event the repurchase agreement fails to meet the look-through requirements of rule 5b–3. *See* Rule 5b–3 Adopting Release, *infra* note 27, at section II.C. The ability of funds to rely on rule 5b–3 of the Investment Company Act may affect the degree to which a fund invests in repurchase agreements.

[26] Rule 5b–3(a). The term ''collateralized fully'' is defined in rule 5b–3(c)(1). In general, under rule 5b–3, a fund investing in a repurchase agreement looks to the value and liquidity of the securities collateralizing the repurchase agreement rather than the creditworthiness of the counterparty for satisfaction of the repurchase agreement. *See* Rule 5b–3 Adopting Release, *infra* note 27, at section II.A.3. *But see* rule 2a–7(c)(4)(ii)(A) (requiring money market fund boards to evaluate the counterparty's creditworthiness).

[27] *See* Treatment of Repurchase Agreements and Refunded Securities as an Acquisition of the Underlying Securities, Investment Company Act Release No. 25058 (July 5, 2001) [66 FR 36156 (July 11, 2001)] (''Rule 5b–3 Adopting Release''). Repurchase agreements provide funds with a convenient means to invest excess cash on a secured basis, generally for short periods of time.

[28] Government Security means ''any security issued or guaranteed as to principal or interest by the United States, or by a person controlled or supervised by and acting as an instrumentality of the Government of the United States pursuant to authority granted by the Congress of the United States; or any certificate of deposit for any of the foregoing.'' Section 2(a)(16) of the Investment Company Act. Government securities include, for example, U.S. Treasury notes and bonds, and securities issued by the Federal Home Loan Mortgage Company (''Freddie Mac''), Federal National Mortgage Association (''Fannie Mae''), and Government National Mortgage Association (''Ginnie Mae'').

[29] The term ''requisite NRSROs'' means any two NRSROs that have issued a rating with respect to a security or class of debt obligations of an issuer or, if only one NRSRO has issued a rating with respect to such security or class of debt obligations of an issuer at the time the investment company acquires the security, that NRSRO. Rule 5b–3(c)(6). This definition is deleted under the amended rule.

[30] Rule 5b–3(c)(1)(iv). The term ''unrated securities'' means securities that have not received a rating from the requisite NRSROs. Rule 5b–3(c)(8). This definition is deleted under the amended rule.

[31] *See* Treatment of Repurchase Agreements and Refunded Securities as an Acquisition of the Underlying Securities, Investment Company Act Release No. 24050 (Sept. 23, 1999) [64 FR 52476 (Sept. 29, 1999)] (''Rule 5b–3 Proposing Release'') at n.43 and accompanying text.

[32] Amended rule 5b–3(c)(1)(iv)(C).

[33] *See supra* section II.A.

[34] *See* rule 2a–7(a)(5).

[35] *See* proposed rule 5b–3(c)(1)(iv)(C)(1).

[36] Federated Investors, Inc. Comment Letter (Apr. 25, 2011) (''Federated Comment Letter''); Investment Company Institute Comment Letter (Apr. 25, 2011) (''ICI Comment Letter''); T. Rowe Price Associates, Inc. Comment Letter (Apr. 25, 2011) (''T. Rowe Price Comment Letter''). *But see* 2011 Proposing Release (discussing the proposed ''highest capacity'' standard and noting that ''[a]n issuer of collateral securities that the board (or its delegate) determined has an exceptionally strong capacity to repay its short or long-term debt obligations . . . would satisfy the proposed [highest capacity] standard'').

[37] *See* Standard & Poor's Ratings Definitions, *infra* note 39 at 5 (which may designate an ''A–1'' rating with a plus sign to designate the obligor's capacity to meet its financial obligations is extremely strong).

[38] *See* ICI Comment Letter; Federated Comment Letter (supporting the ICI Comment Letter); and T.

Continued

standard, as revised from our proposal, because we believe that, like the current rule, it permits some variation in creditworthiness among issuers while being designed to retain a degree of risk limitation similar to the current rule.[39] In the case of asset-backed securities that serve as collateral, an evaluation of the capacity of the issuer to meet its financial commitment on the security should include an assessment of the quality of the underlying assets and the structure of the asset-backed security.[40]

As discussed above, we are adopting the liquidity component of the new standard as proposed. The liquidity standard in the amended rule is similar to the standard used in rule 2a–7 governing money market funds, and is also used in other rules under the Investment Company Act.[41] No commenters addressed the proposed liquidity standard.

We expect that securities that actively trade in a secondary market at the time of the acquisition of the repurchase agreement will satisfy the liquidity component of the standard. We also understand that most securities used to collateralize repurchase agreements generally actively trade in a secondary market.[42] Securities that do not actively trade in a secondary market would likely require a more in-depth evaluation by the board or its delegate to determine whether they meet the liquidity standard.

The final amendments do not, as one commenter suggested, include specific factors or tests that the board or its delegate must apply in performing its credit analysis.[43] This commenter acknowledged that a reliable and objective shorthand measure of credit risk that could be incorporated into Commission regulations is currently unavailable.[44] The Commission considered including specific factors for funds to consider in performing credit analysis under rule 5b–3. On balance, we believe that, in the context of rule 5b–3, the new credit quality standards provide sufficiently clear criteria under which a fund board or its delegate can make determinations regarding credit quality and liquidity for this particular purpose. Fund boards should also be familiar with applying similar credit quality standards used in other Commission rules.[45] Fund boards may also consult external resources and Commission staff guidance (if applicable) for additional guidance on making credit quality determinations in certain circumstances.[46]

The new credit quality standard is intended to achieve the same objectives that the credit rating requirement was designed to achieve, *i.e.,* to limit collateral securities to those that are likely to retain a sufficiently stable market value and that, under ordinary circumstances, the fund would be able to liquidate quickly, at or near their carrying value in the event of a counterparty default.[47] Amended rule 5b–3 would not, however, prohibit a fund board from establishing its own additional criteria for what the fund may accept as collateral for repurchase agreements under the amended rule.

Under the final rule, as was proposed, the fund's board will be required to make credit quality determinations for all collateral securities that are not cash items or government securities, rather than just for unrated securities. In addition, as in the current rule, the amended rule continues to permit the board to delegate these credit quality and liquidity determinations.[48] We do not agree with the concerns of one commenter that this determination will impose undue burdens on the board because the determination is similar to what rule 5b–3 currently requires a fund board (or its delegate) to make with respect to unrated collateral securities.[49] In addition, the amended rule will continue to permit the board of directors to delegate credit quality and liquidity determinations that the board believes

Rowe Price Comment Letter (generally agreeing with the ICI Comment Letter).

[39] *See* Fitch Ratings, International Issuer and Credit Rating Scales, *http://www.fitchratings.com/web_content/ratings/fitch_ratings_definitions_and_scales.pdf* (stating that a rating of AAA is used in cases of ''exceptionally strong capacity for payment of financial commitments''); Moody's Investor Service Rating Symbols and Definitions, *https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_79004* (stating that ratings of Aaa are of the ''highest quality, subject to the lowest level of credit risk''); and Standard & Poor's Ratings Definitions, *http://img.en25.com/Web/StandardandPoors/Ratings_Definitions.pdf* (stating that for a rating of AAA, ''[t]he obligor's capacity to meet its financial commitment on the obligation is extremely strong'').

[40] *See* Revisions to Rules Regulating Money Market Funds, Investment Company Act Release No. 19959 (Dec. 17, 1993) [58 FR 68585 (Dec. 28, 1993)] at text accompanying nn.108–109 (''[t]he credit quality of a typical asset backed security depends both upon the structure of the security and the quality of the underlying assets.''); Money Market Fund Reform, Investment Company Act Release No. 29132 (Feb. 23, 2010) [75 FR 10060 (Mar. 4, 2010)] at text accompanying n.131 (noting that the minimal credit risk analysis that a money market fund board (or its delegate) must conduct before investing in an asset-backed security should include, among other things, (i) an analysis of the underlying assets to ensure they are properly valued and provide sufficient asset coverage for the cash flow required to fund the asset-backed security under various market conditions and (ii) an analysis of the terms of any liquidity or other support provided by the sponsor of the asset-backed security). *See also* Alternatives to the Use of External Credit Ratings in the Regulations of the Office of the Comptroller of the Currency (June 4, 2012) [77 FR 35253 (June 13, 2012)] at text following n.2 (in adopting an issuer-based credit quality standard to replace credit ratings, the OCC indicates that, in the case of a structured finance transaction, principal and interest repayment is not necessarily solely reliant on the direct debt repaying capacity of the issuer or obligor).

[41] *See* rule 2a–7(a)(19) (defining illiquid security to mean a security that cannot be sold or disposed of in the ordinary course of business within seven calendar days at approximately the value ascribed to it by the fund). *See also* rule 10f–3(a)(3) (requiring, among other things, that ''eligible municipal securities'' be sufficiently liquid that they can be sold at or near their carrying value within a reasonably short period of time).

[42] Repurchase agreements are often collateralized by securities that include, but are not limited to, agency collateralized mortgage-backed obligations (''CMOs''), agency debentures and strips, agency mortgage-backed securities, private label CMOs, corporate debt, equity securities, money market instruments and U.S. Treasury securities. *See, e.g.,* Tri-Party Repo Statistical Data (as of August 2013), *http://www.newyorkfed.org/banking/tpr_infr_reform_data.html.* The securities that often collateralize repurchase agreements trade frequently. For example, data from the Securities Industry and Financial Markets Association for January through August 2013 shows average daily trading volume, in billions of dollars, as follows: Agency debentures and strips ($7.1); agency mortgage-backed securities ($242.9); corporate debt ($145.4); U.S. Treasury securities ($551.4) (available at *http://www.sifma.org/research/statistics.aspx*).

[43] *See* Better Markets Comment Letter (Apr. 25, 2011) (''Better Markets Comment Letter''). This commenter suggested certain factors that they believed funds should be required to consider when evaluating the creditworthiness of an issuer or a debt security.

[44] *Id.* We note that another commenter that recommended that we establish an objective standard for credit quality determinations did not provide any examples of such criteria. *See* New York City Bar Committee on Investment Management Regulation Comment Letter (Apr. 29, 2011) (''NY City Bar Comment Letter'').

[45] *See* adopting release, *supra* note 16 (the Commission adopted amendments to rule 10f–3, revising the definition of ''eligible municipal security'' by replacing references to credit ratings with a similar two-part credit quality standard). *See also* text accompanying note 49.

[46] *See, e.g.,* Tri-Party Repo Infrastructure, Reform Task Force, *http://www.newyorkfed.org/tripartyrepo/. See cf.* Securities and Exchange Commission, Division of Investment Management, IM Guidance Update, *Counterparty Risk Management Practices With Respect to Tri-Party Repurchase Agreements* (July 2013) (providing guidance to funds on the legal and operational steps that funds should consider if a counterparty fails and defaults on its obligations under a tri-party repurchase agreement), available at *http://www.sec.gov/divisions/investment/guidance/im-guidance-2013-03.pdf.*

[47] *See supra* note 31.

[48] This is similar to rule 2a–7, which permits the board to delegate decisions regarding credit quality. *See* rule 2a–7(e).

[49] *See* NY City Bar Comment Letter (asserting that fund boards would be assigned responsibility for making determinations that are not within their expertise and arguing that the ability to delegate the determination does not relieve them of ultimate responsibility). *See also infra* section V.b.2. *See* rule 5b–3(c)(1)(iv)(D) (requiring that unrated securities other than government securities be ''of comparable quality'' to securities rated in the highest category by requisite NRSROs).

are within the delegate's expertise if the board retains sufficient oversight.[50]

Under the amended rule, when determining credit quality and liquidity, the board (or its delegate) may incorporate into its analysis ratings, reports, opinions and other assessments issued by third parties, including NRSROs. A board should evaluate the basis for using any third-party assessment, including an NRSRO rating, in determining whether collateral meets the new standard and would not rely on the use of an NRSRO rating as a standard by itself without evaluating the quality of each NRSRO's assessment. In this way, the board could determine which third-party providers are credible and reliable and provide assessments that would be most appropriate to incorporate in making determinations under the amended rule. Delegation of these functions, as well as the use of third-party providers, may help to limit the potential increase in burdens on the board. One commenter suggested that we not allow a fund board to consider credit ratings in determining if a repurchase agreement is fully collateralized, stating that this would conflict with section 939A of the Dodd-Frank Act.[51] We believe, however, that credit ratings can serve as a useful data point for evaluating credit quality, and as noted above, a fund's board (or its delegate) may not rely solely on the credit ratings of an NRSRO without performing additional due diligence.

A fund that enters into repurchase agreements and relies on rule 5b–3 must maintain written policies and procedures that are reasonably designed to comply with the conditions of the rule, including the credit quality and liquidity requirements we are adopting today, and funds may therefore have to amend their policies and procedures.[52] We also understand that credit quality standards for securities collateralizing repurchase agreements are typically negotiated in the agreements between funds and counterparties.[53] We understand that those standards currently include a rating (for rated collateral securities) and any additional criteria that a fund manager considers necessary to ensure that the credit quality of collateral securities meets the fund's requirements, or, for unrated securities, a comparable credit quality standard. The amended rule does not prohibit fund boards (or their delegates) from considering the credit quality standards in current repurchase agreements and policies and procedures adopted to comply with the current rule as part of their analysis, provided that fund boards (or their delegates) determine that the ratings specified in the repurchase agreements and policies and procedures meet the standards we are adopting today, and that the agencies providing the ratings used in the policies and procedures are credible and reliable for that use. A fund could also revise its repurchase agreements and policies and procedures to change or eliminate the consideration of specific credit ratings or to incorporate other third-party evaluations of credit quality.[54]

As discussed above, amended rule 5b–3 replaces the requirement that collateral for repurchase agreements consist of securities rated in the highest category by the requisite NRSROs (other than cash and government securities) with a requirement that the collateral other than cash and government securities consist of securities issued by an issuer that has an exceptionally strong capacity to meet its financial obligations and that are sufficiently liquid. Consistent with the protection of investors and as necessary and appropriate in the public interest, we are also amending rule 5b–3 to define an issuer to include an issuer of an unconditional guarantee of the security.[55] We proposed this amendment to preserve a fund's ability to use the same types of collateral securities as it currently uses to satisfy the conditions of rule 5b–3. We received no comments on this aspect of the proposal and are adopting it as proposed. Thus, under amended rule 5b–3, a collateral security with an unconditional guarantee, the issuer of which meets the new credit quality test, satisfies that element of the standard.

B. Forms N–1A, N–2, and N–3

We are also adopting amendments to Forms N–1A, N–2, and N–3 to remove the required use of credit ratings assigned by an NRSRO. Forms N–1A, N–2, and N–3, among other things, contain the requirements for shareholder reports of mutual funds, closed-end funds, and certain insurance company separate accounts that offer variable annuities.[56]

Currently, Forms N–1A, N–2, and N–3 require shareholder reports to include a table, chart, or graph depicting portfolio holdings by reasonably identifiable categories (*e.g.,* type of security, industry sector, geographic region, credit quality, or maturity).[57] The forms require the categories to be selected in a manner reasonably designed to depict clearly the types of investments made by the fund, given its investment objectives. If credit quality is used to present portfolio holdings, the forms currently require that credit quality be depicted using the credit ratings assigned by a single NRSRO. We are amending Forms N–1A, N–2, and N–3, as proposed, to no longer *require* the use of NRSRO credit ratings by funds that choose to use credit quality categorizations in the required table, chart, or graph of portfolio holdings. Accordingly, funds that choose to show credit quality categorizations in the required table, chart, or graph may use alternative categorizations that are not based on NRSRO credit ratings.

In a change from the 2011 Proposing Release, however, under the amended forms, funds that choose to continue to

[50] *See* Amended rule 5b–3(c)(1)(iv)(C); *see also* 2011 Proposing Release, *supra* note 10, at n.51 (''As in the current rule, the proposed rule would permit the board to delegate this credit quality and liquidity determination.''). We expect that a fund's written policies and procedures would include guidelines for the fund's delegate (typically, the investment adviser) in making required determinations under rule 5b–3 and oversight of the fund adviser's compliance in making such determinations. *See* rule 38a–1. These policies and procedures typically would identify the process to be followed by the board (or its delegate) in making these credit and liquidity evaluations, including, as appropriate, the types of data to be used or factors to be considered and the person(s) or position(s) responsible. They also typically would provide for regular reporting to the board, as appropriate, about these evaluations, to allow the board to provide effective oversight of the process.

[51] *See* Better Markets Comment Letter.

[52] Registered funds are required to adopt and implement written policies and procedures reasonably designed to prevent the fund's violation of federal securities laws. *See* rule 38a–1(a); *see also infra* sections IV.A and V.B.

[53] Many repurchase market participants will only accept AAA-rated paper such as government bonds as collateral. *See* Moorad Choudhry, The Repo Handbook (2d ed. 2010) at 298. Counterparties to repurchase agreements generally assess counterparty credit risk exposure based on the ''haircut''—For example, $100 of securities collateralizing a loan of $97 produces a 3% haircut. The haircut may be greater depending on the counterparties' assessment of the collateral provider's creditworthiness. *See* Repo and Securities Lending, Staff Report No. 529, Federal Reserve Bank of New York (Dec. 2011, Rev. Feb. 2013). Assessments of credit quality are not standardized but are participant specific and negotiated at the time of the transaction. *Id.*

[54] *See* 2011 Proposing Release, *supra* note 10, at n.58. An estimate of the potential costs is discussed *infra* at section IV.A.

[55] Amended rule 5b–3(c)(4) (defining ''issuer'' to mean ''the issuer of a collateral security or the issuer of an unconditional obligation of a person other than the issuer of the collateral security to undertake to pay, upon presentment by the holder of the obligation (if required), the principal amount of the underlying collateral security plus accrued interest when due or upon default.'').

[56] Open-end management investment companies, commonly known as mutual funds, use Form N–1A. Closed-end management investment companies use Form N–2. Separate accounts organized as management investment companies that offer variable annuity contracts use Form N–3.

[57] Item 27(d)(2) of Form N–1A; Instruction 6(a) to Item 24 of Form N–2; Instruction 6(i) to Item 28(a) of Form N–3.

use credit ratings will no longer be restricted to using the credit ratings assigned by a single NRSRO. Accordingly, funds that choose to depict credit quality using credit ratings assigned by a credit rating agency may use different credit rating agencies for split-rated securities (*i.e.,* securities that have received different ratings from multiple credit rating agencies) and they may use ratings provided by credit rating agencies that are not NRSROs.[58] Funds will also be required to describe how the credit quality of the holdings was determined, and if credit ratings are used, a description of how they were identified and selected.[59]

Four of the five substantive comments we received on the proposed amendments to Forms N–1A, N–2, and N–3, supported eliminating the required use of NRSRO credit ratings to depict credit quality.[60] Two of these commenters noted that shareholders would benefit from information about the credit quality of a fund's portfolio securities, whether determined by an NRSRO or internally.[61]

Although most commenters supported eliminating the required use of credit ratings to depict credit quality, four commenters opposed the proposed requirement that a fund that chooses to use NRSRO credit ratings must use the credit ratings of a single NRSRO. Instead, these commenters recommended that when a security is split-rated, the fund be permitted to choose which NRSRO rating to use, provided the choice is made consistently pursuant to a disclosed policy.[62] These commenters argued that this approach would benefit funds and investors by allowing funds to disclose credit quality information in shareholder reports in a manner consistent with marketing materials and internal investment policies.[63]

We agree with commenters and have revised the final form amendments to provide this additional degree of flexibility. Accordingly, the amended forms permit funds to consider alternative approaches to presenting credit quality that accurately and effectively describe the credit quality of the fund's portfolio. For example, under the amended forms, a fund could have a policy of disclosing the median credit quality rating for split-rated securities instead of only using the ratings of a single credit rating agency (when more than two rating agencies rate the security).[64] In the 2011 Proposing Release, we proposed to maintain the general requirement that ratings be selected from a single NRSRO because we were concerned about the possibility that a fund may select the most favorable credit ratings among credit ratings assigned by multiple NRSROs. On balance, we are persuaded by commenters that the benefits of this additional flexibility outweigh the potential ''cherry picking'' concern. We believe that the risks associated with cherry picking ratings are mitigated by the disclosure requirements discussed below.[65] For example, if a fund discloses that, with respect to split-rated securities, it is the fund's policy to select the highest credit rating provided by a credit rating agency, investors will be on notice that the fund has made a decision not to include potentially lower and more conservative measures of credit quality. In addition, we believe that in some circumstances selecting credit ratings from more than one credit rating agency may reflect a more comprehensive approach to credit quality analysis that results in information about credit quality that may be more accurate or complete. For example, a fund that reviews credit ratings from three rating agencies, discards the outliers (*i.e.,* the highest and lowest ratings), and selects the middle rating,[66] has evaluated credit quality from a broader set of market participants that may lead to a more complete evaluation of credit quality.

Under the amended forms, funds that choose to depict portfolio holdings according to credit quality must include a description of how the credit quality of the holdings was determined.[67] This description should include a discussion of the credit quality evaluation process, the rationale for its selection, and an overview of the factors considered, such as the terms of the security (*e.g.,* interest rate, and time to maturity), the obligor's capacity to repay the debt, and the quality of any collateral. If the fund uses credit ratings issued by a credit rating agency to depict credit quality, the fund should explain how the credit ratings were identified and selected, and include this description near, or as part of, the graphical representation.[68] This description should include, if applicable, a discussion of: (i) The criteria considered or process used in selecting the credit ratings (*e.g.,* the fund might use the median credit rating from among three rating agencies[69]); (ii) how the fund evaluated those criteria (*i.e.,* the due diligence performed); (iii) how the fund reports credit ratings for any security that is not rated by the credit rating agency selected if the fund has a policy of using the ratings of a

[58] We are replacing the term ''ratings'' with ''credit ratings'' and ''nationally recognized statistical rating organization 'NRSRO' '' with ''credit rating agency'' as defined under the Exchange Act. *See* sections 3(a)(60) [15 U.S.C. 78c(a)(60)] and 3(a)(61) [15 U.S.C. 78c(a)(61)] of the Exchange Act, which define ''credit rating'' and ''credit rating agency'', respectively.

[59] *See* Amended Item 27(d)(2) of Form N–1A; Amended Instruction 6(a) to Item 24 of Form N–2; Amended Instruction 6(i) to Item 28(a) of Form N–3.

[60] ICI Comment Letter; Vanguard Comment Letter; T. Rowe Price Comment Letter; Federated Comment Letter (supporting the ICI's comments). The fifth commenter argued that the Commission is not required to remove references to credit ratings from the forms pursuant to section 939A of the Dodd-Frank Act. *See* BlackRock Comment Letter. Regardless of whether the Commission is required to remove from the forms references to credit ratings, the Commission believes that the removal of such references is consistent with the purpose of section 939A of the Dodd-Frank Act.

[61] ICI Comment Letter; Federated Comment Letter (supporting the ICI's comments).

[62] ICI Comment Letter; Vanguard Comment Letter; T. Rowe Price Comment Letter; Federated Comment Letter (supporting the ICI's comments). Two commenters noted that the Financial Industry Regulatory Authority (''FINRA'') permits funds to use different approaches to portray the credit quality of split-rated bonds in marketing materials (noting further that funds receive credit rating information through data feeds and that it would be more cost efficient for funds to rely on a single data feed to comply with one consistent SEC/FINRA requirement). *See* ICI Comment Letter; Vanguard Comment Letter.

[63] *See* ICI Comment Letter; Federated Comment Letter (supporting the ICI's comments); Vanguard Comment Letter.

[64] *See infra* note 70 and accompanying and following text (discussing the difference between using median and average credit ratings).

[65] *See* Amended Item 27(d)(2) of Form N–1A; Amended Instruction 6(a) to Item 24 of Form N–2; Amended Instruction 6(i) to Item 28(a) of Form N–3.

[66] *See, e.g.,* Fact Sheet, BlackRock Bond Index Fund (portraying credit quality using the median credit rating from among S&P, Moody's, and Fitch, when all three agencies rate a security), available at *https://www2.blackrock.com/webcore/litService/search/getDocument.seam?venue=PUB_IND&source=CONTENT&serviceName=publicServiceView&ContentID=1111147239&venue=FP_ML;* Fact Sheet, Vanguard High-Yield Tax-Exempt Fund Investor Shares (same), available at *https://personal.vanguard.com/us/funds/snapshot?FundId=0044&FundIntExt=INT.*

[67] *See supra* note 65; *see also* ICI Comment Letter (recommending that funds be permitted to choose which NRSRO rating to use for split-rated securities, provided that the choice is made pursuant to a disclosed policy).

[68] If a fund does not use credit ratings, its description of how the credit quality of the holdings was determined would also need to be near, or as part of, the graphical representation. *See* Amended Item 27(d)(2) of Form N–1A; Amended Instruction 6(a) to Item 24 of Form N–2; Amended Instruction 6(i) to Item 28(a) of Form N–3.

[69] For example, Morningstar prefers that bonds be classified using the Barclays Capital Family of Indices ratings rules (*i.e.,* use the middle rating of Moody's, S&P and Fitch after dropping the highest and lowest available ratings; if only two rating agencies rate a security then the lowest rating should be used; and if only one agency rates a security then that rating should be used). *See* Morningstar Fixed-Income Style Box Methodology (Apr. 30, 2012) at *http://corporate.morningstar.com/us/documents/MethodologyDocuments/MethodologyPapers/FixedIncomeStyleBoxMeth.pdf.*

single rating agency (*e.g.,* has the fund selected a designated alternate rating agency); (iv) how the fund reports credit ratings for any security that is not rated by any credit rating agency (*i.e.,* the process for self-rating); or (v) other fund policies on selecting credit ratings for purposes of disclosure. We expect that this discussion, modified and expanded upon by funds as appropriate, will provide investors with insight into how the fund identified and selected the credit ratings used in depicting the fund's portfolio by credit quality.

We recognize that under the final form amendments, a fund has a variety of options when depicting its portfolio holdings using credit quality. For example, a fund might choose not to use credit ratings and could rely instead on internal credit assessments. If a fund does not use credit ratings, we note that it might be misleading for a fund to describe its portfolio holdings quality with similar descriptions as the ratings nomenclature used by rating agencies (*e.g.,* AAA, Aa), or to characterize the securities as ''rated.'' If a fund chooses to depict its portfolio using credit ratings issued by a credit rating agency, a fund could choose to use the *median* credit rating from among multiple credit rating agencies (discarding the highest and lowest ratings) when a security is split-rated.[70] We note, however, that it might be misleading for a fund to disclose an *average* credit quality rating that is based on ratings from multiple credit rating agencies because credit rating agencies may use different criteria to evaluate the credit quality of an issuer. A fund might also choose other methods for evaluating credit quality of portfolio securities, such as a policy of selecting the highest or lowest credit rating for split-rated securities among the ratings issued by certain specified rating agencies.[71] As discussed above, a fund must include in its disclosure a description of how the credit quality of the holdings was determined, no matter the method used.

The amended forms are intended to provide funds with the flexibility to present credit ratings in a manner that more clearly explains the credit quality of the fund's portfolio and the method by which the fund determined that quality.

IV. Paperwork Reduction Act

Certain provisions of the amendments we are adopting contain ''collections of information'' within the meaning of the Paperwork Reduction Act of 1995 (''PRA'').[72] The titles for the existing collections of information we are amending are: (i) ''Rule 30e–1 under the Investment Company Act of 1940, Reports to Stockholders of Management Companies'';[73] and (ii) ''Rule 38a–1 under the Investment Company Act of 1940, Compliance procedures and practices of registered investment companies.'' We adopted those rules pursuant to the Investment Company Act. There is currently no approved collection of information for rule 5b–3, and the amendments do not create any new collections under that rule. The amendments to rule 5b–3 do, however, affect the collection of information burden for rule 38a–1.

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 control number. We published notice soliciting comments on the collection of information requirements in the 2011 Proposing Release and submitted the proposed collections of information to the Office of Management and Budget (''OMB'') for review in accordance with 44 U.S.C. 3507(d) and 5 CFR 1320.11 under the control numbers 3235–0025 (rule 30e–1) and 3235–0586 (rule 38a–1). We received no comments on the PRA estimates contained in the 2011 Proposing Release.

A. Rule 38a–1

Rule 5b–3 under the Investment Company Act allows funds to treat the acquisition of a repurchase agreement as an acquisition of securities collateralizing the repurchase agreement for purposes of sections 5(b)(1) and 12(d)(3) of the Investment Company Act under certain conditions. Rule 5b–3, as amended, requires that the securities collateralizing a repurchase agreement consist of securities that the fund's board of directors, or its delegate, determines are issued (or have unconditional guarantees that are issued) by an issuer that has an exceptionally strong capacity to meet its financial obligations and are highly liquid.[74] To that end, the fund's board of directors, pursuant to rule 38a–1 under the Investment Company Act, must have procedures that are reasonably designed to ensure that the fund is able to comply with the conditions of amended rule 5b–3, including the credit quality and liquidity requirements outlined in the amended rule.[75] As discussed above, these procedures should be designed to limit collateral securities to those that are likely to retain a stable market value and that, in ordinary circumstances, the fund would be able to liquidate quickly in the event of a default. This rule 38a–1 collection of information will be mandatory for funds that rely on rule 5b–3. Records of information made in connection with this requirement will be required to be maintained for inspection by Commission staff, but the collection will not otherwise be submitted to the Commission. To the extent that the Commission receives confidential information pursuant to this collection of information, such information would be kept confidential, subject to the provisions of applicable law.[76]

We do not anticipate that the amendments to rule 5b–3 will significantly change collection of information burdens under rule 38a–1 because we believe funds would likely rely significantly on their current policies and procedures to determine the credit quality of collateral securities and comply with amended rule 5b–3. As we indicated above, we understand that credit quality standards for securities collateralizing repurchase agreements typically are contained in the repurchase agreements between funds and counterparties.[77] We understand that those standards currently include a rating (for rated collateral securities) and any additional criteria a fund manager considers

[70] *Id.; see also supra* note 66.

[71] *See, e.g.,* Fact Sheet, Fidelity Institutional Money Market Prime Money Market Portfolio—Institutional CL (categorizing portfolio credit quality for investment grade taxable and municipal bond funds and multi-asset class funds with a fixed income component using the highest credit rating among Moody's, S&P, or Fitch), available at *https://fundresearch.fidelity.com/mutual-funds/composition/31607A208.*

[72] 44 U.S.C. 3501–3520.

[73] The amendments to Forms N–1A, N–2, and N–3 relate solely to the contents of fund shareholder reports. The PRA burden associated with fund shareholder reports is included in the burden associated with the collection of information for rule 30e–1 under the Investment Company Act rather than Forms N–1A, N–2 and N–3.

[74] Amended rule 5b–3(c)(1)(iv)(C). *See supra* section III.A.

[75] Under rule 38a–1, funds must have written policies and procedures reasonably designed to prevent violation of the federal securities laws. Rule 38a–1(a)(1). Funds thus would have policies and procedures for complying with rule 5b–3, which would include policies and procedures relating to credit quality determinations of unrated collateral securities, if appropriate.

[76] *See, e.g.,* 5 U.S.C. 552. Exemption 4 of the Freedom of Information Act provides an exemption for ''trade secrets and commercial or financial information obtained from a person and privileged or confidential.'' 5 U.S.C. 552(b)(4). Exemption 8 of the Freedom of Information Act provides an exemption for matters that are ''contained in or related to examination, operating, or condition reports prepared by, on behalf of, or for the use of an agency responsible for the regulation or supervision of financial institutions.'' 5 U.S.C. 552(b)(8).

[77] *See supra* note 53 and accompanying text.

necessary to ensure that the credit quality of the collateral securities meets the fund's requirements, or, for unrated securities, a comparable credit quality standard. Counterparties provide collateral securities to conform to these standards and funds confirm that the securities are conforming. As we have noted above, funds can continue to consider evaluations of outside sources, including credit ratings that the board determines are credible and reliable in making their credit quality determinations under the amended rule. We expect that funds will likely continue to rely on their current policies and procedures (*i.e.,* using credit quality standards that include ratings currently set forth in their repurchase agreements with counterparties). Thus, we do not expect that the amendments to rule 5b–3 will significantly change the current collection of information burden estimates for rule 38a–1.[78] Nevertheless, funds may review their repurchase agreements and policies and procedures that address rule 5b–3 compliance and make technical changes to those documents in response to the amendments. Staff estimated in the proposal and continues to believe that it will take, on average, 1.5 hours of a senior business analyst's time to perform this review and make any technical changes for an individual fund portfolio, for an estimated one-time additional burden of 15,176 hours for all fund portfolios (other than money market fund portfolios).[79] Amortized over three years, the staff estimates that the estimated annual aggregate burden will be 5,059 burden hours.[80]

We anticipate that the fund's board will review the fund manager's recommendation, but that the cost of this review will be incorporated in the fund's overall annual board costs and would not result in any particular additional cost. We received no comments on these estimates and therefore have not modified them.[81]

B. Rule 30e–1

The amendments to Forms N–1A, N–2, and N–3 eliminate the required use of NRSRO credit ratings by funds that choose to use credit quality categorizations in the table, chart, or graph of portfolio holdings provided in shareholder reports. The collection of information is mandatory for those funds that choose to use credit quality categorizations in these forms. If a fund chooses to depict portfolio holdings according to credit quality, the fund must include a description of how the credit quality of the holdings was determined. If credit ratings assigned by a credit rating agency are used, the fund must disclose how it identified and selected the credit ratings. Responses to the disclosure requirements will not be kept confidential.

Although funds would remain obligated to provide a table, chart, or graph of portfolio holdings by reasonably identifiable categories, the amendments require that certain funds must make new disclosures. Under our proposed amendment, we estimated that there would be no additional collection of information burden as a result of proposing to remove the required use of credit ratings from the forms.[82] Under our amended rule, however, funds that choose to use credit quality categorizations must disclose how the fund made the credit quality determinations, and if the fund uses credit ratings issued by a credit rating agency, the fund must disclose how it identified and selected the credit ratings.[83]

Accordingly, based on staff experience, the staff estimates that it will take, on average, 3 hours of an attorney's time to perform this review and make any technical changes to an individual fund's disclosures, for an estimated burden of 32,049 hours for all funds.[84] Amortized over three years, the staff estimates that the estimated annual aggregate burden will be 10,683 burden hours and that there will be approximately 10,683 respondents.[85]

V. Economic Analysis

A. Overview

As discussed above, we are adopting rule and form amendments to implement section 939A of the Dodd-Frank Act. The amendments to rule 5b–3 replace a NRSRO credit rating standard with alternative credit quality and liquidity criteria that are designed to achieve the same purposes as the NRSRO credit rating standard without imposing unnecessarily burdensome costs. The amendments to Forms N–1A, N–2, and N–3 remove the required use of credit ratings when portraying credit quality in shareholder reports, but require that those funds include a description of how the credit quality of the holdings were determined, and if credit ratings assigned by a credit rating agency are used, how the credit ratings were identified and selected. The regulatory changes adopted today will directly affect investment companies registered under the Investment Company Act and could affect the demand for rating agencies' services by eliminating the required use of NRSRO credit ratings in rule 5b–3 and Forms N–1A, N–2, and N–3. The amendments to

[78] The current approved annual burden for rule 38a–1 under the PRA is 248,455 hours. As discussed below, as amended, the collection of information requirement will be 263,631 hours (248,455 + 15,176).

[79] For purposes of this PRA analysis, we assume that all funds enter into repurchase agreements and rely on rule 5b–3. We have not included money market funds in our estimates, however, because they are subject to different requirements for the collateralization of repurchase agreements under rule 2a–7. *See* text accompanying note 34. The staff's estimate is based on staff examination of industry data as of August 31, 2013 and includes 10,117 fund portfolios. We therefore estimate that there will be 10,117 respondents to this collection of information. The amount is calculated as follows: 10,117 fund portfolios × 1.5 hours = 15,176 one-time additional burden hours for all fund portfolios. We estimate that the one-time additional annual burden is 1.5 hours per respondent.

The monetized burden hours are calculated as follows: 15,176 hours × $245 per hour = $3,718,120 one-time additional costs. The staff estimates that the internal cost for time spent by a senior business analyst is $245 per hour. This estimate, as well as other internal time cost estimates made in this analysis, is derived from SIFMA's Management and Professional Earnings in the Securities Industry 2012, modified by Commission staff to account for an 1800-hour work week and multiplied by 5.35 to account for bonuses, firm size, employee benefits and overhead.

[80] The amount is calculated as follows: 15,176 burden hours/3 = 5,059 burden hours. Amortized over three years, staff estimates that the annual aggregate burden cost will be: $3,718,820/3 = $1,239,373.

[81] The PRA costs have been modified slightly since the 2011 Proposing Release to reflect a more current estimate of the number of fund portfolios affected, as well as updated hourly wages based on the 2012 SIFMA table.

[82] *See* 2011 Proposing Release, section IV.C.

[83] The current approved annual burden for rule 30e–1 under the PRA is 903,000 hours. As discussed below, as amended, the collection of information requirement will be 935,049 hours (903,000 + 32,049).

[84] The staff's estimate of the number of funds is based on staff examination of industry data as of August 31, 2013 and includes 10,683 funds that collectively file reports on Forms N–1A, N–2, and N–3 each year. We note that this estimate is conservative because it is likely that some fund complexes will achieve economies of scale when revising their disclosures, do not use credit quality when describing portfolio holdings, or whose current disclosures already satisfy the requirements of the amended rule and thus would not need to make any changes. The amount is calculated as follows: 10,683 funds × 3 hours = 32,049 one-time additional burden hours for all funds. We estimate that the one-time additional annual burden is 3 hours per respondent.

The monetized burden hours are calculated as follows: 32,049 hours × $379 per hour = $12,146,571 one-time additional costs. The staff estimates that the internal cost for time spent by an in-house attorney is $379 per hour. This estimate, as well as other internal time cost estimates made in this analysis, is derived from SIFMA's Management and Professional Earnings in the Securities Industry 2012, modified by Commission staff to account for an 1800-hour work week and multiplied by 5.35 to account for bonuses, firm size, employee benefits and overhead.

[85] The amount is calculated as follows: 32,049 burden hours/3 = 10,683 burden hours. Amortized over three years, staff estimates that the annual aggregate burden cost will be: $12,146,571/3 = $4,048,857.

rule 5b–3 may also affect other parties such as repurchase agreement counterparties (*e.g.,* broker-dealers and banks), investors, and issuers of collateral securities. Finally, we recognize that the elimination of the required use of NRSRO credit ratings in rule 5b–3 and Forms N–1A, N–2, and N–3 may reduce the incentive for credit rating agencies to register as NRSROs and thereby be subject to the Commission's oversight and statutory and regulatory requirements applicable to NRSROs. We received no comments on the cost-benefit analysis contained the 2011 Proposing Release.

At the outset, the Commission notes that, where possible, we have attempted to quantify the costs and benefits expected to result from adopting the amendments to rule 5b–3 and Forms N–1A, N–2, and N–3. However, wherever the discussion of costs or benefits is not quantified in this section it is because the Commission is unable to quantify the economic effects because it lacks the information necessary to provide a reasonable estimate. For example, as discussed below, the Commission does not have available to it comprehensive information on the exposure of funds to different repurchase agreement market segments, the nature and type of collateral used in repurchase agreements, or the extent to which funds rely on rule 5b–3. Because of this lack of data, including the extent to which funds may rely on rule 5b–3, we are unable to quantify the costs to comply with the amended rule and note that the costs could vary from our estimates. We discuss below the economic baseline, costs and benefits of our final rule and form amendments, alternatives considered, as well as the impact on efficiency, competition, and capital formation.

B. Rule 5b–3

Rule 5b–3, as amended, permits a fund to treat the acquisition of a repurchase agreement as an acquisition of securities collateralizing the repurchase agreement for purposes of sections 5(b)(1) and 12(d)(3) of the Investment Company Act if the collateral other than cash or government securities consists of securities that the fund's board of directors, or its delegate, determines at the time the repurchase agreement is entered into are: (i) Issued by an issuer that has an exceptionally strong capacity to meet its financial obligations; and (ii) sufficiently liquid that they can be sold at approximately their carrying value in the ordinary course of business within seven calendar days.

1. Economic Baseline

The economic baseline against which we measure the economic effects of these amendments is the regulatory framework as it exists immediately before the adoption of today's amendments. Currently, rule 5b–3 allows funds to treat the acquisition of a repurchase agreement as an acquisition of securities collateralizing the repurchase agreement for certain diversification and broker-dealer counterparty limit purposes under the Investment Company Act if the obligation of the seller to repurchase the securities from the fund is ''collateralized fully.'' In general, under rule 5b–3, a fund investing in a repurchase agreement looks to the value and liquidity of the securities collateralizing the repurchase agreement rather than the creditworthiness of the counterparty for satisfaction of the repurchase agreement. Under current requirements, a repurchase agreement is collateralized fully if, among other things, the collateral for the repurchase agreement consists entirely of (i) cash items, (ii) government securities, (iii) securities that at the time the repurchase agreement is entered into are rated in the highest rating category by the ''Requisite NRSROs'' or (iv) unrated securities that are of a comparable quality to securities that are rated in the highest rating category by the Requisite NRSROs, as determined by the fund's board of directors or its delegate.

As of the end of 2012, the total repurchase agreement market approximated $3 trillion.[86] The repurchase agreement market has two primary segments, bilateral and tri-party.[87] The bilateral segment comprises cash-driven transactions against specific collateral while the tri-party segment comprises cash-driven transactions against general collateral. We believe that investment companies' primary exposure to repurchase agreements is through the tri-party market, but the Commission does not have available to it comprehensive information on the exposure in either market segment. The collateral used in the approximately $2 trillion tri-party market is dominated by government securities: Approximately 35% consists of Treasury securities and approximately 50% consists of agency mortgage-backed securities, agency debentures, and agency collateralized mortgage obligations.[88]

While we believe that many funds invest in tri-party repurchase agreements, comprehensive information about the extent to which funds invest in these agreements is not available to us. Nor are we able to estimate how often funds rely on rule 5b–3 when entering into repurchase agreements, or the extent to which fund repurchase agreements are collateralized with securities other than cash or government securities. However, we are able to estimate the extent of money market fund participation in the tri-party repurchase market using Form N–MFP data, which shows that money market funds held approximately $591 billion in tri-party repurchase agreements as of the end of 2012. While we understand almost all funds rely on rule 5b–3 on occasion (for example when approaching diversification limits or avoiding restrictions on investments in certain entities), we do not have the information necessary to determine how frequently those funds rely on rule 5b–3 in their daily transactions in repurchase agreements. Accordingly, we are largely unable to quantify the benefits and costs discussed below.

2. Economic Analysis

Amended rule 5b–3 is intended to establish a similar credit quality standard to the NRSRO credit rating standard we are replacing in order to achieve the same objectives that the NRSRO credit rating reference requirement was designed to achieve in the existing rule, *i.e.,* limit collateral securities to those that are likely to retain a stable market value and that, under ordinary circumstances, the fund would be able to liquidate quickly at or near its carrying value in the event of a counterparty default. Although amended rule 5b–3 seeks to maintain a similar degree of credit quality as the standard it replaces, the Dodd-Frank Act mandate is designed to reduce reliance on NRSRO credit ratings.[89]

Some fund boards or their delegates, after independent analysis, might make a determination of credit quality that comports with the analysis of the NRSRO credit ratings and, accordingly, make no substantive changes to the funds' investments in repurchase agreements. Other fund boards might turn to non-NRSRO sources (''third-party providers'') to satisfy the new requirements, which may result in a different pool of assets from which the funds may select for collateralizing

[86] *See* Financial Stability Oversight Council, 2013 Annual Report at 65–66, available at *http://www.treasury.gov/initiatives/fsoc/Documents/FSOC%202013%20Annual%20Report.pdf.*

[87] *See id.* (noting a third repo market segment—the general collateral finance market—which primarily settles inter-dealer transactions on the tri-party repo platform).

[88] *Id.*

[89] *See supra* note 12.

repurchase agreements. We believe that this flexibility of allowing for a broader range of credit quality models will increase competition for such models, whether from internal assessments made by the fund or from external assessments made by third-party providers such as credit rating agencies. As a result, credit assessments, and the repurchase agreement market in general, may become more efficient and may promote capital formation through a more accurate assessment of credit risk that may increase investment in repurchase agreements.

We recognize, as discussed above, that funds typically establish standards for the credit quality of collateral securities (that include credit ratings and additional credit quality criteria required by the fund) in repurchase agreements with counterparties.[90] Funds could change their policies and procedures to reflect changes made to the rule by the amendments, but the rule would not prohibit funds from considering the standards in current repurchase agreements and policies and procedures provided that the fund's board or its delegate made the determination that those standards satisfy the standards in amended rule 5b–3. As a result, amended rule 5b–3 may not significantly change the types of collateral securities held by funds relying on rule 5b–3.

Amended rule 5b–3 requires the fund's board or its delegate to make a determination about the collateral of each repurchase agreement. This will increase the regulatory burden on the fund's board,[91] but we believe that the burden is significantly reduced by the fund board's ability to incorporate ratings, reports, analyses, and other assessments issued by third parties, including NRSRO ratings that the fund's board concludes are credible and reliable for purposes of making the evaluation. Moreover, fund boards that find these increased regulatory burdens to be excessive can mitigate them by restricting the fund to repurchase agreement collateral that consists of cash and government securities.

If the fund's board decides to rely primarily on NRSRO ratings as part of the process of evaluating credit quality, the fund may incur some additional costs from today's amendments.[92] However, some fund boards may decide not to rely primarily on NRSRO ratings, perhaps because of a more cost efficient way of making the required determinations or because they believe NRSRO ratings are not helpful or sufficient in evaluating credit quality. Reducing the emphasis on NRSRO ratings could also adversely affect the quality of NRSRO ratings. Currently, the importance attached to NRSRO ratings may impart franchise value to the NRSRO's ratings business. By eliminating references to NRSRO ratings in Federal regulations, section 939A of the Dodd-Frank Act could reduce these franchise values and mitigate NRSROs' incentives to produce credible and reliable ratings. Moreover, the Commission recognizes that the elimination of the required use of credit ratings in Commission rules and forms may reduce the incentive for credit rating agencies to register as NRSROs with the Commission and thereby be subject to the Commission's oversight and the statutory and regulatory requirements applicable to NRSROs. To the extent that the quality and accuracy of NRSRO ratings is adversely affected, negative impacts on the capital allocation process and economic efficiency would result.

The new methodologies that the fund's board employs may result in a pool of assets from which the fund may select for collateralizing repurchase agreements that is different from a pool based on NRSRO ratings. This may affect the fund relative to the baseline of NRSRO ratings by including or excluding as collateral assets that are different from the collateral permitted under the current rule. In turn, this could increase the credit risk in the pool of collateral assets or decrease the return earned by investing in repurchase agreements. Both of these effects may lead to a less efficient market for repurchase agreement collateral. Issuers' ability to raise capital may also be adversely affected to the extent that issuers of collateral securities lose the regulatory preference that currently exists because of the required use of NRSRO ratings within rule 5b–3. We do not, however, believe that the amended rule is likely to lead to the acceptance of riskier collateral in practice because the standard we are adopting is very similar to the standard articulated by the NRSROs for securities that have received the highest ratings. In addition, we anticipate that fund boards and advisers will retain the credit quality standards in their current repurchase agreements and their existing policies and procedures that address compliance with current rule 5b–3 and include ratings that they believe are credible and reliable.

Although we believe that boards of funds relying on rule 5b–3 have established policies and procedures for complying with the rule,[93] funds may incur costs to revise existing policies and procedures for investing in repurchase agreements to comply with amended rule 5b–3. We recognize that increased compliance costs are a necessary result of our amendments to rule 5b–3 and may disproportionately impact smaller funds to the extent these funds do not today have policies and procedures for assessing creditworthiness. As noted above, we are not able to quantify many of the costs (and benefits) discussed above. However, we estimate that each fund will incur, at a minimum, the collection of information costs discussed in the Paperwork Reduction Act section for a total average one-time cost of approximately $368 per fund.[94] Funds may also incur additional costs in complying with the amendments which we are unable to quantify, for the reasons discussed above.

3. Alternatives

In adopting today's amendments to rule 5b–3, the Commission considered, as noted by one commenter, including specific factors or tests that a fund board must apply in performing its credit analysis under the rule.[95] As noted above, the number and scope of factors that may be appropriate to making a credit quality determination with respect to a security may vary significantly depending on the particular security and through time. Accordingly, we are not adopting specific factors or tests that a fund board must apply in performing credit analysis, but may provide guidance in the future.[96]

We also considered different standards to replace credit ratings that would help ensure that funds can liquidate collateral quickly in the event of a default. These alternatives included, for example, omitting an explicit liquidity requirement because securities in the ''highest rating category'' generally are more liquid than lower quality securities. Other liquidity alternatives we considered included limiting collateral securities only to cash and government securities because liquidity may decline between the time of acquisition and the time of default, or prohibiting a fund from relying on rule

[90] *See supra* text preceding note 53.

[91] *See* NY City Bar Comment Letter, *supra* note 44.

[92] *See supra* text following note 53.

[93] *See* rule 38a–1(a).

[94] *See supra* note 79 and accompanying text. Staff estimates that all funds will incur a one-time aggregate cost of approximately $3.7 million to make any necessary changes related to collections of information under the Paperwork Reduction Act. *Id.*

[95] *See supra* note 43.

[96] *See supra* notes 43–46 and accompanying text.

5b–3 if, at any point after the time a fund enters into a repurchase agreement, the collateral could no longer be liquidated within seven calendar days. After considering the alternatives, we believe that amended rule 5b–3 strikes a better balance than the alternatives by imposing a liquidity requirement that is similar to the liquidity standard inherent to the credit quality rating required under the current rule, while not unduly restricting funds' flexibility to utilize a larger pool of assets for collateralizing repurchase agreements.

C. Forms N–1A, N–2, and N–3

Forms N–1A, N–2, and N–3, as amended, eliminate the required use of NRSRO credit ratings by funds that choose to use credit quality categorizations in the required table, chart, or graph of portfolio holdings. If a fund chooses to depict portfolio holdings according to credit quality, the fund must include a description of how the credit quality of the holdings was determined. If a fund uses credit ratings assigned by a credit rating agency to depict credit quality, the fund must disclose how it identified and selected the credit ratings.

1. Economic Baseline

As noted above, the economic baseline against which we measure the economic effects is the regulatory framework as it exists immediately before the adoption of today's amendments. Currently, Forms N–1A, N–2, and N–3 require shareholder reports to include a table, chart, or graph depicting portfolio holdings by reasonably identifiable categories (*e.g.,* type of security, industry sector, geographic region, credit quality, or maturity). The forms require the categories to be selected in a manner reasonably designed to depict clearly the types of investments made by the fund, given its investment objectives. If credit quality is used to present portfolio holdings, the forms currently require that credit quality be depicted using the credit ratings assigned by a single NRSRO.

We believe, based on staff experience, that the majority of funds choose to depict their portfolios using credit quality, and accordingly, report credit ratings from a single NRSRO. As discussed above, we conservatively estimate that 10,683 funds collectively file reports on Forms N–1A, N–2, and N–3 each year and will be affected by the amendments.[97]

2. Economic Analysis

The Dodd-Frank Act mandate is designed to reduce potential reliance on NRSRO credit ratings. Under the amendments, funds have greater flexibility to assess and depict credit quality, which may lead to better-informed investors who can, in turn, make better capital allocation decisions. Accordingly, better-informed investors may make more effective investment decisions based on their risk tolerance and may promote increased competition among funds. We note, however, that funds might choose to report credit quality in a more positive light than is possible under the prior requirement to use the credit ratings from a single NRSRO. However, as discussed above, the disclosure requirements we are adopting today should mitigate many of the potential adverse consequences. As a result, today's amendments may have a varied effect on investors' ability to make effective capital allocation choices.

Because we do not anticipate that these amendments will result in large changes in the portfolios held by funds or their investors, we do not believe the amendments would have more than a marginal effect on efficiency or capital formation. A potential benefit may arise by allowing funds to use different credit rating agencies for split-rated securities because that may promote competition between credit rating agencies to provide ratings that are more accurate if funds use the most accurate ratings for each part of their portfolios even if those ratings come from different credit rating agencies. This may foster innovation in the industry, and it may foster the growth of niche credit rating agencies. Although some funds may eliminate the specific use of credit ratings in their depiction of portfolio credit quality, we anticipate that many of those funds are likely to consider some outside analyses in evaluating the credit quality of portfolio securities.[98] A fund's consideration of external analyses by third-party sources determined to be credible and reliable may contribute to the accuracy of funds' determinations and thus help funds arrive at consistent and more accurate depictions of credit quality.

Under the amended forms, funds may continue to depict portfolio holdings as they do today: Funds can continue to depict portfolio holdings without making reference to credit quality, and funds can continue to depict portfolio holdings using credit ratings from one NRSRO. Today's amendments impose no new costs on funds that depict portfolio holdings based on criteria other than credit quality, but they do impose small additional costs on funds that choose to portray portfolio holdings using credit ratings from one NRSRO because they must make new disclosures about how the ratings were identified and selected. We believe that the majority of costs related to today's amendments to Forms N–1A, N–2, and N–3 are the costs described above related to the collections of information under the Paperwork Reduction Act. Accordingly, we estimate that funds on average will incur costs of approximately $1,137 per fund in complying with the amendments.[99] In addition, funds may voluntarily incur additional costs if they choose to develop and apply new methodologies to depict credit quality. Funds that choose to do so will incur a cost not only to determine the credit quality of portfolio holdings but also a cost to include in the registration statement a description of how the credit quality of portfolio holdings was determined, and if credit ratings are used, how the ratings were identified and selected.

3. Alternatives

In adopting the amendments to the forms, the Commission considered replacing the required use of credit ratings with an option to depict a fund's portfolio by credit quality using the credit ratings of only a single credit rating agency. This approach, proposed in 2011, was intended to eliminate the possibility that a fund could choose to use NRSRO credit ratings and then select the most favorable ratings among the credit ratings assigned by multiple NRSROs. As discussed above, a number of commenters suggested that funds be permitted to use the credit ratings assigned by more than one NRSRO for split-rated securities, provided the choice is made consistently, pursuant to a disclosed policy. On balance, we believe that the benefits of this additional flexibility outweigh the potential costs associated with the possibility that funds cherry pick the highest credit rating available. We note that the risks associated with cherry picking ratings are mitigated by the fact that the forms, as amended, require that

[97] *See supra* note 84.

[98] Funds may elect to use a combination of factors, including NRSRO credit ratings, in depicting credit quality; or funds may use or establish entirely new methods of depicting credit quality. *See* ICI Comment Letter; Federated Comment Letter (supporting the ICI Comment Letter).

[99] *See supra* note 84 and accompanying text. Staff estimates that all funds will incur a one-time aggregate cost of approximately $12.1 million to make any necessary changes to the registration statement related to collections of information under the Paperwork Reduction Act. *Id.*

funds disclose how they identified and selected the credit ratings, which would include, for example, a fund policy that selects the highest credit rating available.

VI. Final Regulatory Flexibility Analysis

The Commission has prepared the following Final Regulatory Flexibility Analysis (''FRFA'') in accordance with section 4(a) of the Regulatory Flexibility Act regarding the rule and form amendments we are adopting today to give effect to provisions of the Dodd-Frank Act.[100] The FRFA relates to amendments to rule 5b–3 under the Investment Company Act and Forms N–1A, N–2, and N–3 under the Investment Company Act and Securities Act. We prepared an Initial Regulatory Flexibility Analysis (''IRFA'') in conjunction with the 2011 Proposing Release in March 2011.[101]

A. Need for and Objectives of the Rule and Form Amendments

As described more fully in sections I and III of this Release, to implement section 939A of the Dodd-Frank Act, the Commission is adopting amendments to (i) rule 5b–3 to eliminate references to the credit rating and replace it with an alternative standard of creditworthiness that is intended to achieve the same objectives that the credit rating requirement was designed to achieve and (ii) Forms N–1A, N–2, and N–3 to eliminate the required use of NRSRO credit ratings by funds that choose to use credit quality categorizations in the required table, chart, or graph of portfolio holdings in their shareholder reports, and to permit funds that choose to depict credit quality using credit ratings assigned by a credit rating agency to use different credit rating agencies for split-rated securities.

B. Significant Issues Raised by Public Comment

In the 2011 Proposing Release, we requested comment on the IRFA. In particular, we sought comment on how many small entities would be subject to the proposed rule and form amendments and whether the effect of the proposed rule and form amendments on small entities subject to them would be economically significant. None of the comment letters we received addressed the IRFA. None of the comment letters made comments about the effect of the rule and form amendments on small investment companies.

C. Small Entities Subject to the Rule and Form Amendments

The amendments to rule 5b–3 and Forms N–1A, N–2, and N–3 under the Investment Company Act would affect funds, including entities that are considered to be a small business or small organization (collectively, ''small entity'') for purposes of the Regulatory Flexibility Act.

Investment Companies. Under Commission rules, for purposes of the Investment Company Act and the Regulatory Flexibility Act, an investment company is a small entity if it, together with other investment companies in the same group of related investment companies, has net assets of $50 million or less as of the end of its most recent fiscal year.[102] Based on a current review of filings submitted to the Commission, we estimate that 171 investment companies may be considered small entities and that all of these investment companies may potentially rely on rule 5b–3.[103] As discussed above, we recognize that increased compliance costs are a necessary result of the amendments to rule 5b–3 and may disproportionately impact smaller funds to the extent these funds do not have policies and procedures for assessing creditworthiness. Based on a current review of filings submitted to the Commission, we estimate that approximately 131 investment companies that meet the definition of small entity would be subject to the amendments to Forms N–1A, N–2, and N–3.

D. Projected Reporting, Recordkeeping, and Other Compliance Requirements

Rule 5b–3. The amendments to rule 5b–3 allow a fund to treat the acquisition of a repurchase agreement as an acquisition of securities collateralizing the repurchase agreement for purposes of sections 5(b)(1) and 12(d)(3) of the Investment Company Act if the collateral other than cash or government securities consists of securities that the fund's board of directors (or its delegate) determines at the time the repurchase agreement is entered into are: (i) Issued by an issuer that has an exceptionally strong capacity to meet its financial obligations; and (ii) sufficiently liquid that they can be sold at approximately their carrying value in the ordinary course of business within seven calendar days. A fund that acquires repurchase agreements and intends the acquisition to be treated as an acquisition of the collateral securities must determine whether it must change its policies for evaluating collateral securities under the amended rule and must adopt and implement written policies and procedures reasonably designed to comply with the conditions of amended rule 5b–3, including these credit quality and liquidity requirements that we are adopting.[104] The costs associated with the amendments to rule 5b–3 are those discussed in section IV.A and V.B above.

Forms N–1A, N–2, and N–3. The amendments to Forms N–1A, N–2, and N–3 apply to open-end management investment companies, closed-end management investment companies, and separate accounts organized as management investment companies that offer variable annuity contracts, including those that are small entities. The amendments to Forms N–1A, N–2, and N–3 eliminate the required use of NRSRO credit ratings by funds that choose to use credit quality categorizations in the required table, chart, or graph of portfolio holdings in their shareholder reports. If a fund chooses to depict portfolio holdings according to credit quality, it must include a description of how the credit quality of the holdings was determined, and if credit ratings assigned by a credit rating agency are used to depict credit quality, the fund must disclose how it identified and selected the credit ratings. The amended forms also permit funds that choose to depict credit quality using credit ratings assigned by a credit rating agency to use different credit rating agencies for split-rated securities. The costs associated with the amendments to the forms are those discussed in section IV.B and V.C above.

E. Agency Action To Minimize Effect on Small Entities

The Regulatory Flexibility Act directs us to consider significant alternatives that would accomplish our stated objectives, while minimizing any significant adverse effect on small entities. In connection with the rule and form amendments, the Commission considered the following alternatives: (i) Establishing different compliance standards or timetables that take into account the resources available to small

[100] 5 U.S.C. 604(a).

[101] *See* 2011 Proposing Release, *supra* note 10, at section VIII.

[102] 17 CFR 270.0–10(a).

[103] The 183 investment companies that meet the definition of small entity include 12 business development companies, which are subject to sections 5 and 12 of the Investment Company Act. 15 U.S.C. 80a–58; 15 U.S.C. 80a–59.

[104] 17 CFR 270.38a–1(a).

entities; (ii) clarifying, consolidating, or simplifying compliance and reporting requirements under the rule for small entities; (iii) use of performance rather than design standards; and (iv) exempting small entities from all or part of the requirements.

We believe that special compliance or reporting requirements for small entities, or an exemption from coverage for small entities, is not appropriate or consistent with investor protection or the Dodd-Frank Act. We believe that, with respect to rule 5b–3, different credit quality standards, special compliance requirements or timetables for small entities, or an exemption from coverage for small entities, may create a risk that those entities could acquire repurchase agreements with collateral that is less likely to retain its market value or liquidity in the event of a counterparty default. Further consolidation or simplification of the rule and form amendments for funds that are small entities is inconsistent with the Commission's goals of fostering investor protection.

The form amendments apply to all investment companies that use Forms N–1A, N–2, and N–3 to register under the Investment Company Act and to offer their securities under the Securities Act. If the Commission had excluded small entities from the form amendments, small entities would have been required to use NRSRO credit ratings if they chose to depict credit quality, while other entities would not have been subject to that requirement. We believe that special compliance or reporting requirements, or an exemption, for small entities would not be appropriate because the amended requirement—eliminating the required use of credit ratings where a fund chooses to depict the fund's portfolio based on credit quality—is intended to eliminate potential reliance on NRSRO credit ratings resulting from the perception that the Commission endorses the ratings because of their required use in Commission forms.

We have endeavored through the form amendments to minimize regulatory burdens on investment companies, including small entities, while meeting our regulatory objectives. We have endeavored to clarify, consolidate, and simplify the requirements applicable to investment companies, including those that are small entities. Finally, the amendments will use performance rather than design standards for determining the credit quality of specific securities. For these reasons, we have not adopted alternatives to rule 5b–3 and Forms N–1A, N–2, and N–3.

Statutory Authority

The Commission is adopting amendments to rule 5b–3 under the authority set forth in sections 6(c) and 38(a) of the Investment Company Act [15 U.S.C. 80a–6(c), 80a–37(a)] and section 939A of the Dodd-Frank Act. The Commission is adopting amendments to Form N–1A, Form N–2, and Form N–3 under the authority set forth in sections 5, 6, 7, 10 and 19(a) of the Securities Act [15 U.S.C. 77e, 77f, 77g, 77j, and 77s(a)]; sections 8, 24(a), 30 and 38 of the Investment Company Act [15 U.S.C. 80a–8, 80a–24(a), 80a–29, and 80a–37]; and section 939A of the Dodd-Frank Act.

List of Subjects

17 CFR Part 239

Reporting and recordkeeping requirements, Securities.

17 CFR Parts 270 and 274

Investment companies, Reporting and recordkeeping requirements, Securities.

Text of Rule and Rule and Form Amendments

For reasons set out in the preamble, Title 17, Chapter II of the Code of Federal Regulations is amended as follows:

PART 239—FORMS PRESCRIBED UNDER THE SECURITIES ACT OF 1933

■ 1. The authority citation for Part 239 is revised to read in part as follow:

Authority: 15 U.S.C. 77f, 77g, 77h, 77j, 77s, 77z–2, 77z–3, 77sss, 78c, 78*l,* 78m, 78n, 78*o*(d), 78o–7, 78o–7 note, 78u–5, 78w(a), 78*ll,* 78mm, 80a–2(a), 80a–3, 80a–8, 80a–9, 80a–10, 80a–13, 80a–24, 80a–26, 80a–29, 80a–30, 80a–37, and Pub. L. 111–203, sec. 939A, 124 Stat. 1376 (2010), unless otherwise noted.

* * * * *

PART 270—RULES AND REGULATIONS, INVESTMENT COMPANY ACT OF 1940

■ 2. The authority citation for Part 270 is revised to read in part as follows:

Authority: 15 U.S.C. 80a–1 *et seq.,* 80a–34(d), 80a–37, 80a–39, and Pub. L. 111–203, sec. 939A, 124 Stat. 1376 (2010), unless otherwise noted.

* * * * *

■ 3. Section 270.5b–3 is amended by:
■ a. Adding ''or'' at the end of paragraph (c)(1)(iv)(B);
■ b. Revising paragraph (c)(1)(iv)(C);
■ c. Removing paragraph (c)(1)(iv)(D);
■ d. Removing paragraphs (c)(5), (c)(6), and (c)(8);
■ e. Redesignating paragraph (c)(4) as (c)(5);
■ f. Adding new paragraph (c)(4); and
■ g. Redesignating paragraph (c)(7) as paragraph (c)(6).

The revisions and addition read as follows:

§ 270.5b–3 Acquisition of repurchase agreement or refunded security treated as acquisition of underlying securities.

* * * * *

(c) * * *

(1) * * *

(iv) * * *

(C) Securities that the investment company's board of directors, or its delegate, determines at the time the repurchase agreement is entered into:

(1) Each issuer of which has an exceptionally strong capacity to meet its financial obligations; and

Note to paragraph (c)(1)(iv)(C)(*1*): For a discussion of the phrase ''exceptionally strong capacity to meet its financial obligations'' see Investment Company Act Release No. 30847, (December 27, 2013).

(2) Are sufficiently liquid that they can be sold at approximately their carrying value in the ordinary course of business within seven calendar days; and

* * * * *

(4) *Issuer,* as used in paragraph (c)(1)(iv)(C)(*1*) of this section, means the issuer of a collateral security or the issuer of an unconditional obligation of a person other than the issuer of the collateral security to undertake to pay, upon presentment by the holder of the obligation (if required), the principal amount of the underlying collateral security plus accrued interest when due or upon default.

* * * * *

PART 239—FORMS PRESCRIBED UNDER THE SECURITIES ACT OF 1933

PART 274—FORMS PRESCRIBED UNDER THE INVESTMENT COMPANY ACT OF 1940

■ 4. The authority citation for Part 274 is revised to read in part as follows:

Authority: 15 U.S.C. 77f, 77g, 77h, 77j, 77s, 78c(b), 78l, 78m, 78n, 78o(d), 80a–8, 80a–24, 80a–26, 80a–29, and Pub. L. 111–203, sec. 939A, 124 Stat. 1376 (2010), unless otherwise noted.

* * * * *

■ 5. Form N–1A (referenced in §§ 239.15A and 274.11A) is amended by revising Item 27(d)(2) to read as follows:

Note: The text of Form N–1A does not, and these amendments will not, appear in the Code of Federal Regulations.

FORM N–1A

* * * * *

Item 27. Financial Statements

* * * * *

(d) *Annual and Semi-Annual Reports.* * * *

(2) *Graphical Representation of Holdings.* One or more tables, charts, or graphs depicting the portfolio holdings of the Fund by reasonably identifiable categories (*e.g.,* type of security, industry sector, geographic region, credit quality, or maturity) showing the percentage of net asset value or total investments attributable to each. The categories and the basis of presentation (*e.g.,* net asset value or total investments) should be selected, and the presentation should be formatted, in a manner reasonably designed to depict clearly the types of investments made by the Fund, given its investment objectives. If the Fund depicts portfolio holdings according to credit quality, it should include a description of how the credit quality of the holdings were determined, and if credit ratings, as defined in section 3(a)(60) of the Securities Exchange Act [15 U.S.C. 78(c)(a)(60)], assigned by a credit rating agency, as defined in section 3(a)(61) of the Securities Exchange Act [15 U.S.C. 78(c)(a)(61)], are used, explain how they were identified and selected. This description should be included near, or as part of, the graphical representation.

* * * * *

■ 6. Form N–2 (referenced in §§ 239.14 and 274.11a–1) is amended by revising Instruction 6.a. to Item 24 to read as follows:

Note: The text of Form N–2 does not, and these amendments will not, appear in the Code of Federal Regulations.

FORM N–2

* * * * *

Item 24. Financial Statements

* * * * *

Instructions:

* * * * *

6. * * *

a. one or more tables, charts, or graphs depicting the portfolio holdings of the Fund by reasonably identifiable categories (*e.g.,* type of security, industry sector, geographic region, credit quality, or maturity) showing the percentage of net asset value or total investments attributable to each. The categories and the basis of presentation (*e.g.,* net asset value or total investments) should be selected, and the presentation should be formatted, in a manner reasonably designed to depict clearly the types of investments made by the Fund, given its investment objectives. If the Fund depicts portfolio holdings according to credit quality, it should include a description of how the credit quality of the holdings were determined, and if credit ratings, as defined in section 3(a)(60) of the Securities Exchange Act [15 U.S.C. 78(c)(a)(60)], assigned by a credit rating agency, as defined in section 3(a)(61) of the Securities Exchange Act [15 U.S.C. 78(c)(a)(61)], are used, explain how they were identified and selected. This description should be included near, or as part of, the graphical representation.

* * * * *

■ 7. Form N–3 (referenced in §§ 239.17a and 274.11b) is amended by revising Instruction 6.(i) to Item 28(a) to read as follows:

Note: The text of Form N–3 does not, and these amendments will not, appear in the Code of Federal Regulations.

FORM N–3

* * * * *

Item 28. Financial Statements

(a) * * *

Instructions:

* * * * *

6. * * *

(i) One or more tables, charts, or graphs depicting the portfolio holdings of the Fund by reasonably identifiable categories (*e.g.,* type of security, industry sector, geographic region, credit quality, or maturity) showing the percentage of net asset value or total investments attributable to each. The categories and the basis of presentation (*e.g.,* net asset value or total investments) should be selected, and the presentation should be formatted, in a manner reasonably designed to depict clearly the types of investments made by the Fund, given its investment objectives. If the Fund depicts portfolio holdings according to credit quality, it should include a description of how the credit quality of the holdings were determined, and if credit ratings, as defined in section 3(a)(60) of the Securities Exchange Act [15 U.S.C. 78(c)(a)(60)], assigned by a credit rating agency, as defined in section 3(a)(61) of the Securities Exchange Act [15 U.S.C. 78(c)(a)(61)], are used, explain how they were identified and selected. This description should be included near, or as part of, the graphical representation.

* * * * *

By the Commission.

Dated: December 27, 2013.

Lynn M. Powalski,

Deputy Secretary.

[FR Doc. 2013–31425 Filed 1–7–14; 8:45 am]

BILLING CODE P

DEPARTMENT OF VETERANS AFFAIRS

38 CFR Part 17

RIN 2900–AO62

Community Residential Care

AGENCY: Department of Veterans Affairs.

ACTION: Final rule.

SUMMARY: This rule adopts as final, without change, an interim final rule amending the Department of Veterans Affairs (VA) regulations concerning approval of non-VA community residential care (CRC) facilities to allow VA to waive such facilities' compliance with standards that do not jeopardize the health or safety of residents. As amended, the regulation allows VA to grant a waiver of a CRC standard in those limited circumstances where the deficiency cannot be corrected to meet a standard provided for in VA regulation. This rulemaking also makes a certain necessary technical amendment to correct a reference to the section addressing requests for a hearing.

DATES: *Effective Date:* This final rule is effective January 8, 2014.

FOR FURTHER INFORMATION CONTACT: Nancy Quest, Director, Home and Community Based Services (10P4G), Veterans Health Administration, 810 Vermont Avenue NW., Washington, DC 20420, (202) 461–6064. (This is not a toll-free number.)

SUPPLEMENTARY INFORMATION: In an interim final rule published in the **Federal Register** on May 29, 2013, at 78 FR 32124, VA amended 38 CFR 17.65, which contains VA's regulations governing approvals and provisional approvals of CRC facilities. The interim final rule allowed VA to waive one or more of the standards in 38 CFR 17.63 for the approval of a particular CRC facility, provided that a VA safety expert certifies that the deficiency does not endanger the life or safety of the residents; the deficiency cannot be corrected; and granting the waiver is in the best interests of the veteran in the facility and VA's CRC program. The rulemaking also made a certain necessary technical amendment to § 17.66. The interim final rule was effective immediately upon publication and provided a 60-day comment period, which ended on July 29, 2013. VA received no public comments and therefore makes no changes to the regulation.

Based on the rationale set forth in the interim final rule, VA is adopting the

interim final rule as a final rule with no changes.

Administrative Procedure Act

In accordance with 5 U.S.C. 553(b)(B) and (d)(3), the Secretary of Veterans Affairs concluded that there was good cause to publish the interim final rule without prior opportunity for public comment and to publish the rule with an immediate effective date. The Secretary found that it was contrary to the public interest to delay this rule for the purpose of soliciting advance public comment or to have a delayed effective date. The interim final rule was necessary to address an immediate need to provide a mechanism that will allow VA to grant a waiver to a CRC facility that cannot obtain full approval because of a minor deviation from regulatory standards that cannot be corrected and does not endanger the lives or safety of the veteran residents. Although approval would be rescinded because of a minor and uncorrectable deviation from standards unrelated to health or safety, veterans may be dissuaded from maintaining their residence in such a facility. Providing a waiver in that circumstance will preclude the need to terminate a CRC facility's approval based on an uncorrectable minor deviation from non-safety related standards. This eliminates the potential that resident veterans will needlessly choose to leave an otherwise healthy, safe, and suitable living arrangement. Regulations in place prior to the effective date of the interim final rule did not provide for any waiver of standards. It is in the public interest for a veteran not to be removed from a stable living situation based solely on a minor deviation from standards that does not threaten life or safety.

To prevent veterans from needlessly choosing to leave affected CRC facilities because the facilities are no longer on the approved list, and in order to ensure timely implementation of the program established by this rule, and for the reasons stated above, the Secretary also found, in accordance with 5 U.S.C. 553(d)(3), good cause for the interim final rule to be effective on the date of publication.

Effect of Rulemaking

Title 38 of the Code of Federal Regulations, as revised by this final rulemaking, represents VA's implementation of its legal authority on this subject. Other than future amendments to this regulation or governing statutes, no contrary guidance or procedures are authorized. All existing or subsequent VA guidance must be read to conform with this rulemaking if possible or, if not possible, such guidance is superseded by this rulemaking.

Paperwork Reduction Act

This final rule contains no provisions constituting a collection of information under the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3501–3521). Documentation that a VA safety expert may request from a CRC facility to support a waiver determination, as provided under 38 CFR 17.65(d)(1), would not qualify as ''information'' under the PRA because collection of this information would be conducted on an individual case-by-case basis and would require individualized information pertaining to the specific deficiency identified by the VA safety expert. We believe that this collection is therefore exempt from the PRA requirements, as provided under 5 CFR 1320.3(h)(6) (excluding from PRA requirements a ''request for facts or opinions addressed to a single person).''

Regulatory Flexibility Act

The Secretary hereby certifies that this final rule will not have a significant economic impact on a substantial number of small entities as they are defined in the Regulatory Flexibility Act, 5 U.S.C. 601–612. This final rule will have little, if any, economic impact on a few small entities. VA may waive a standard under this rulemaking provided a VA safety expert certifies that the deficiency does not endanger the life or safety of the residents, the deficiency cannot be corrected, and granting the waiver is in the best interests of the veteran in the facility and VA's CRC program.

In order to reach the above determinations, the VA safety expert may request supporting documentation from the CRC facility. VA believes supplying this information will constitute an inconsequential amount of the operational cost for those CRC facilities. VA believes that, at most, only a few CRC facilities would qualify for a waiver. On this basis, the Secretary certifies that the adoption of this final rule will not have a significant economic impact on a substantial number of small entities as they are defined in the Regulatory Flexibility Act. Therefore, pursuant to 5 U.S.C. 605(b), this rulemaking is exempt from the initial and final regulatory flexibility analysis requirements of sections 603 and 604.

Executive Order 12866 and 13563

Executive Orders 12866 and 13563 direct agencies to assess the costs and benefits of available regulatory alternatives and, when regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety effects, and other advantages; distributive impacts; and equity). Executive Order 13563 (Improving Regulation and Regulatory Review) emphasizes the importance of quantifying both costs and benefits, reducing costs, harmonizing rules, and promoting flexibility. Executive Order 12866 (Regulatory Planning and Review) defines a ''significant regulatory action,'' requiring review by the Office of Management and Budget (OMB) unless OMB waives such review, as ''any regulatory action that is likely to result in a rule that may: (1) 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; (2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in this Executive Order.''

The economic, interagency, budgetary, legal, and policy implications of this regulatory action have been examined, and it has been determined not to be a significant regulatory action under Executive Order 12866. VA's impact analysis can be found as a supporting document at *http://www.regulations.gov,* usually within 48 hours after the rulemaking document is published. Additionally, a copy of the rulemaking and its impact analysis are available on VA's Web site at *http://www1.va.gov/orpm/,* by following the link for ''VA Regulations Published.''

Unfunded Mandates

The Unfunded Mandates Reform Act of 1995 requires, at 2 U.S.C. 1532, that agencies prepare an assessment of anticipated costs and benefits before issuing any rule that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million or more (adjusted annually for inflation) in any 1 year. This final rule will have no such effect on State, local, and tribal governments, or on the private sector.

Catalog of Federal Domestic Assistance

The Catalog of Federal Domestic Assistance numbers and titles for the programs affected by this document are 64.007, Blind Rehabilitation Centers; 64.008, Veterans Domiciliary Care; 64.009, Veterans Medical Care Benefits; 64.010, Veterans Nursing Home Care; 64.011, Veterans Dental Care; 64.012, Veterans Prescription Service; and 64.022, Veterans Home Based Primary Care.

Signing Authority

The Secretary of Veterans Affairs, or designee, approved this document and authorized the undersigned to sign and submit the document to the Office of the Federal Register for publication electronically as an official document of the Department of Veterans Affairs. Jose D. Riojas, Chief of Staff, Department of Veterans Affairs, approved this document on December 6, 2013, for publication.

List of Subjects in 38 CFR Part 17

Administrative practice and procedure, Alcohol abuse, Alcoholism, Claims, Day care, Dental health, Drug abuse, Foreign relations, Government contracts, Grant programs-health, Government programs-veterans, Health care, Health facilities, Health professions, Health records, Homeless, Medical and dental schools, Medical devices, Medical research, Mental health programs, Nursing homes, Reporting and recordkeeping requirements, Scholarships and fellowships, Travel and transportation expenses, Veterans.

Dated: January 3, 2014.

Robert C. McFetridge,

Director, Office of Regulation Policy and Management, Office of the General Counsel, Department of Veterans Affairs.

Based on the rationale set forth in the **Federal Register** at 78 FR 32124 on May 29, 2013, VA is adopting the interim final rule as a final rule with no changes.

[FR Doc. 2014–00099 Filed 1–7–14; 8:45 am]

BILLING CODE 8320–01–P

DEPARTMENT OF VETERANS AFFAIRS

38 CFR Part 17

RIN 2900–AO51

Removal of Penalty for Breaking Appointments

AGENCY: Department of Veterans Affairs.

ACTION: Final rule.

SUMMARY: The Department of Veterans Affairs (VA) amends its regulations to remove an outdated regulation that stated that a veteran who misses two medical appointments without providing 24 hours' notice and a reasonable excuse is deemed to have refused VA medical care. VA removes this penalty because we believe it is incompatible with regulatory changes implemented after the regulation was promulgated, is not in line with current practice, and is inconsistent with VA's patient-centered approach to medical care.

DATES: *Effective Date:* This rule is effective February 7, 2014.

FOR FURTHER INFORMATION CONTACT: Ethan Kalett, Director, Office of Regulatory Affairs (10B4), Department of Veterans Affairs, 810 Vermont Ave. NW., Washington, DC 20420; (202) 461–5657. (This is not a toll-free number.)

SUPPLEMENTARY INFORMATION: On April 15, 2013, VA published in the **Federal Register** (78 FR 22219) a proposed rule to amend VA regulations by removing § 17.100. This regulation stated that a veteran who misses two medical appointments without providing 24 hours' notice and a reasonable excuse is deemed to have refused VA medical care and no further treatment will be provided to that veteran, except in emergency situations, unless the veteran agrees to cooperate by keeping future appointments. We stated that this penalty is inconsistent with VA's goal of providing patient-centered care, may interfere with continuity and coordination of care, and could have a negative impact on the therapeutic relationship. In addition, refusing to provide further medical services to certain veterans, including homeless veterans and other veterans who lack reliable telephone access or dependable transportation to and from scheduled appointments is counterproductive and may discourage them from attempting to access care in the future. Lastly, providing treatment only in emergent circumstances does not provide an adequate safety net for our patients, especially those with chronic or poorly controlled medical conditions.

Interested persons were invited to submit comments to the proposed rule on or before June 14, 2013, and we received six comments. All of the comments were supportive of removing § 17.100, and did not suggest changes to the proposed removal of the rule. However, two commenters raised issues that we believe should be addressed.

One commenter expressed support for removing this regulation, but suggested a different approach to addressing the issue of broken appointments. The commenter suggested that, after two consecutive missed appointments, VA should follow a series of steps to contact the veteran and to place a limit (''moratorium'') on the care available to the veteran on the particular health issue.

VA appreciates the commenter's input. However, VA has determined that the appropriate course of action is to remove the penalty for breaking appointments. In practice, the problem of missed appointments has been adequately addressed through internal VA processes, as well as by using non-punitive measures and maintaining an open channel of communication between VA clinical/administrative staff and veterans. The penalty contemplated by § 17.100 is incompatible with regulatory changes implemented after that regulation was published, is not in line with current practice, and is inconsistent with VA's patient-centered approach to medical care. Even a short break in a course of treatment can interfere with continuity and coordination of care, and the punitive nature of the regulation could have a negative impact on the therapeutic relationship.

Another commenter supported removing the penalty for breaking medical appointments, but stated that the regulation should be removed because it violates due process protections. VA disagrees. The regulation we remove by this final rule did not terminate a benefit; it merely attempted to facilitate efficient delivery of limited health care resources. The veteran remained enrolled to receive health care, and could receive treatment for any emergent condition that may arise. To schedule a non-emergency medical appointment, the veteran merely had to agree to attend the appointment. In any event, this issue is moot because we are removing the penalty.

This commenter also suggested that VA should employ social workers to be responsible for tracking and contacting veterans who habitually miss medical appointments. VA does use various methods to follow up with those veterans in an effort to ensure they receive necessary medical care. Veterans are contacted via mail, phone, or electronic means after a missed appointment, and are encouraged to contact VA to reschedule.

We do not make any changes based on these comments.

Based on the rationale set forth in the proposed rule and in this final rule, VA is adopting the provisions of the

proposed rule as final, and removes § 17.100.

Effect of Rulemaking

Title 38 of the Code of Federal Regulations, as revised by this final rulemaking, represents VA's implementation of its legal authority on this subject. Other than future amendments to this regulation or governing statutes, no contrary guidance or procedures are authorized. All existing or subsequent VA guidance must be read to conform with this rulemaking if possible or, if not possible, such guidance is superseded by this rulemaking.

Paperwork Reduction Act

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

Regulatory Flexibility Act

The Secretary hereby certifies that this final rule will not have a significant economic impact on a substantial number of small entities as they are defined in the Regulatory Flexibility Act, 5 U.S.C. 601–612. This final rule will directly affect only individuals and will not directly affect small entities. Therefore, pursuant to 5 U.S.C. 605(b), this rulemaking is exempt from the initial and final regulatory flexibility analysis requirements of 5 U.S.C. 603 and 604.

Executive Orders 12866 and 13563

Executive Orders 12866 and 13563 direct agencies to assess the costs and benefits of available regulatory alternatives and, when regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety effects, and other advantages; distributive impacts; and equity). Executive Order 13563 (Improving Regulation and Regulatory Review) emphasizes the importance of quantifying both costs and benefits, reducing costs, harmonizing rules, and promoting flexibility. Executive Order 12866 (Regulatory Planning and Review) defines a ''significant regulatory action'' requiring review by the Office of Management and Budget (OMB), unless OMB waives such review, as ''any regulatory action that is likely to result in a rule that may: (1) 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; (2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in this Executive Order.''

The economic, interagency, budgetary, legal, and policy implications of this final rule have been examined, and it has been determined not to be a significant regulatory action under Executive Order 12866. VA's impact analysis can be found as a supporting document at *http://www.regulations.gov,* usually within 48 hours after the rulemaking document is published. Additionally, a copy of the rulemaking and its impact analysis are available on VA's Web site at *http://www1.va.gov/orpm/,* by following the link for ''VA Regulations Published.''

Unfunded Mandates

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

Catalog of Federal Domestic Assistance

The Catalog of Federal Domestic Assistance numbers and titles for the programs affected by this document are 64.007, Blind Rehabilitation Centers; 64.008, Veterans Domiciliary Care; 64.009, Veterans Medical Care Benefits; 64.010, Veterans Nursing Home Care; 64.011, Veterans Dental Care; 64.012, Veterans Prescription Service; and 64.022, Veterans Home Based Primary Care.

Signing Authority

The Secretary of Veterans Affairs, or designee, approved this document and authorized the undersigned to sign and submit the document to the Office of the Federal Register for publication electronically as an official document of the Department of Veterans Affairs. Jose D. Riojas, Chief of Staff, Department of Veterans Affairs, approved this document on December 20, 2013, for publication.

List of Subjects in 38 CFR Part 17

Administrative practice and procedure, Alcohol abuse, Alcoholism, Claims, Day care, Dental health, Drug abuse, Foreign relations, Government contracts, Grant programs-health, Government programs-veterans, Health care, Health facilities, Health professions, Health records, Homeless, Medical and dental schools, Medical devices, Medical research, Mental health programs, Nursing homes, Reporting and recordkeeping requirements, Scholarships and fellowships, Travel and transportation expenses, Veterans.

Dated: January 3, 2014.

Robert C. McFetridge,

Director, Office of Regulation Policy and Management, Office of the General Counsel, Department of Veterans Affairs.

For the reasons stated in the preamble, the Department of Veterans Affairs amends 38 CFR part 17 as follows:

PART 17—MEDICAL

■ 1. The authority citation for part 17 continues to read as follows:

Authority: 38 U.S.C. 501, and as noted in specific sections.

§ 17.100 [Removed]

■ 2. Remove § 17.100 and the undesignated center heading that precedes it.

[FR Doc. 2014–00098 Filed 1–7–14; 8:45 am]

BILLING CODE 8320–01–P

Proposed Rules

Federal Register

Vol. 79, No. 5

Wednesday, January 8, 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.

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 25

Docket No. FAA–2013–0908; Notice No. 25–13–24–SC]

Special Conditions: Airbus, Model A350–900 Series Airplane; Airplane Level of Safety Provided by Composite Fuel Tank Structure: Post-Crash Fire Survivability.

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed special conditions.

SUMMARY: This action proposes special conditions for Airbus Model A350–900 series airplanes. These airplanes will have a novel or unusual design feature(s) associated with the post-crash fire survivability of composite fuel tanks. The applicable airworthiness regulations do not contain adequate or appropriate safety standards for this design feature. These proposed special conditions contain the additional safety standards that the Administrator considers necessary to establish a level of safety equivalent to that established by the existing airworthiness standards.

DATES: Send your comments on or before February 24, 2014.

ADDRESSES: Send comments identified by docket number FAA–2013–0908 using any of the following methods:

- *Federal eRegulations Portal:* Go to *http://www.regulations.gov/* and follow the online instructions for sending your comments electronically.
- *Mail:* Send comments to Docket Operations, M–30, U.S. Department of Transportation (DOT), 1200 New Jersey Avenue SE., Room W12–140, West Building Ground Floor, Washington, DC, 20590–0001.
- *Hand Delivery or Courier:* Take comments to Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE., Washington, DC, between 8 a.m. and 5 p.m., Monday through Friday, except federal holidays.
- *Fax:* Fax comments to Docket Operations at 202–493–2251.

Privacy: The FAA will post all comments it receives, without change, to *http://www.regulations.gov/*, including any personal information the commenter provides. Using the search function of the docket Web site, anyone can find and read the electronic form of all comments received into any FAA docket, including the name of the individual sending the comment (or signing the comment for an association, business, labor union, etc.). DOT's complete Privacy Act Statement can be found in the **Federal Register** published on April 11, 2000 (65 FR 19477–19478), as well as at *http://DocketsInfo.dot.gov/.*

Docket: Background documents or comments received may be read at *http://www.regulations.gov/* at any time. Follow the online instructions for accessing the docket or go to the Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except federal holidays.

FOR FURTHER INFORMATION CONTACT: Doug Bryant, Propulsion/Mechanical Systems, ANM–112, Transport Airplane Directorate, Aircraft Certification Service, 1601 Lind Avenue SW., Renton, Washington, 98057–3356; telephone (425) 227–2384; facsimile (425) 227–1320.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite interested people to take part in this rulemaking by sending written comments, data, or views. The most helpful comments reference a specific portion of the special conditions, explain the reason for any recommended change, and include supporting data.

We will consider all comments we receive on or before the closing date for comments. We may change these proposed special conditions based on the comments we receive.

Background

On August 25, 2008, Airbus applied for a type certificate for their new Model A350–900 series airplane. Later, Airbus requested and the FAA approved an extension to the application for FAA type certification to June 28, 2009. The Model A350–900 series airplane has a conventional layout with twin wing-mounted Rolls-Royce Trent XWB engines. It features a twin aisle 9-abreast economy class layout, and accommodates side-by-side placement of LD–3 containers in the cargo compartment. The basic Model A350–900 series airplane configuration will accommodate 315 passengers in a standard two-class arrangement. The design cruise speed is Mach 0.85 with a maximum take-off weight of 602,000 lbs. Airbus proposes the Model A350–900 series airplane to be certified for extended operations (ETOPS) beyond 180 minutes at entry into service for up to a 420-minute maximum diversion time.

The Model A350–900 series airplane will be the second large transport category airplane certificated with composite wing and fuel tank structure that may be exposed to the direct effects of post-crash ground or under-wing fuel-fed fires. Although the FAA has previously approved fuel tanks made of composite materials located in the horizontal stabilizer of some airplanes, the composite wing structure of the Model A350–900 series airplane will incorporate a new fuel tank construction into service.

Advisory Circular (AC) 20–107A, Composite Aircraft Structure, under the topic of flammability, states: ''The existing requirements for flammability and fire protection of aircraft structure attempt to minimize the hazard to the occupants in the event ignition of flammable fluids or vapors occurs. The use of composite structure should not decrease this existing level of safety.'' Pertinent to the wing structure, post-crash fire passenger survivability is dependent on the time available for passenger evacuation prior to fuel tank breach or structural failure. Structural failure can be a result of degradation in load-carrying capability in the upper or lower wing surface caused by a fuel-fed ground fire. Structural failure can also be a result of over-pressurization caused by ignition of fuel vapors internal to the fuel tank.

The inherent capability of aluminum to resist fire has been considered by the FAA in development of the current regulations. Title 14 Code of Federal Regulations (14 CFR) part 25 Chapter 1, Section 1.1, General Definitions, defines

fire resistant as follows: ''With respect to sheet or structural members means the capacity to withstand the heat associated with fire at least as well as aluminum alloy in dimensions appropriate for the purpose for which they are used.'' It is noteworthy that aluminum alloy is identified as the performance standard for fire resistance, though no thickness or heat intensities are defined. Based on the performance of aluminum alloy, the definition of fire resistance was later defined for testing of other materials in AC 20–135 as the capability to withstand a 2000° F flame for five minutes.

The FAA has historically promulgated rules with the assumption that the material of construction for wing and fuselage would be aluminum. As a representative case, § 25.963 was promulgated as a result of a large fuel-fed fire following the failures of fuel tank access doors caused by uncontained engine failures. During the subsequent Aviation Rulemaking Advisory Committee (ARAC) harmonization process, the structures group attempted to harmonize § 25.963 regarding the impact and fire resistance of the fuel tank access panels. Discussions between the FAA and the European Aviation Safety Agency (EASA), formerly the European Joint Aviation Authorities (JAA), ensued regarding the need for fire resistance of the fuel tank access panels. The EASA position was that the FAA requirement for the access panels to be fire resistant when the surrounding wing structure was not required to be fire resistant was inconsistent and that the access panels only needed to be as fire resistant as the surrounding tank structure. The FAA position stated that the fuel tank access panel fire resistance requirement should be retained, and that long term there should be a minimum requirement created for the wing skin itself. Both authorities recognized that existing aluminum wing structure provided an acceptable level of safety. Further rulemaking has not yet been pursued.

As with previous Airbus airplane designs with under-wing mounted engines, the wing tanks and center tanks are located in proximity to the passengers and near the engines. Past experience indicates post-crash survivability is greatly influenced by the size and intensity of any fire that occurs. The ability of aluminum wing surfaces wetted by fuel on their interior surface to withstand post-crash fire conditions has been demonstrated by tests conducted at the FAA William J. Hughes Technical Center.[1]

Results of these tests have verified adequate dissipation of heat across wetted aluminum fuel tank surfaces so that localized hot spots do not occur, thus minimizing the threat of explosion. This inherent capability of aluminum to dissipate heat also allows the wing lower surface to retain its load carrying characteristics during a fuel-fed ground fire and significantly delay wing collapse or burn-through for a time interval that usually exceeds evacuation times. In addition, as an aluminum fuel tank is heated with significant quantities of fuel inside, fuel vapor accumulates in the ullage space, exceeding the upper flammability limit relatively quickly and thus reducing the threat of a fuel tank explosion prior to fuel tank burn-through. Service history of conventional aluminum airplanes has shown that fuel tank explosions caused by ground fires have been rare on airplanes configured with flame arrestors in the fuel tank vent lines. Fuel tanks constructed with composite materials may or may not have equivalent capability.

Due to the inherent properties provided by aluminum skin and structure, current regulations may not be adequate as they were developed and have evolved under the assumption that wing construction would be of aluminum materials. Inherent properties of aluminum with respect to fuel tanks and fuel fed fires are as follows:

- Aluminum is highly thermally conductive and readily transmits the heat of a fuel-fed external fire to fuel in the tank. This has the benefit of rapidly driving the fuel tank ullage to exceed the upper flammability limit prior to burn-through of the fuel tank skin or heating of the wing upper surface above the auto-ignition temperature, thus greatly reducing the threat of fuel tank explosion.
- Aluminum panels at thicknesses previously used in wing lower surfaces of large transport category airplanes have been fire resistant as defined in 14 CFR 14 part 1 and AC 20–135.
- Heat capacity of aluminum and fuel will prevent burn-through or wing collapse for a time interval that will generally exceed the passenger evacuation time.

[1] Hill, R., and Johnson, G.R., ''Investigation of Aircraft Fuel Tank Explosions and Nitrogen Inerting Requirements During Ground Fires,'' FAA Report DOT/FAA/RD–75–119, October 1975. Available via the FAA Technical Center Web site for Fire Safety at *http://www.fire.tc.faa.gov/*.

Type Certification Basis

Under Title 14, Code of Federal Regulations (14 CFR) 21.17, Airbus must show that the Model A350–900 series airplane meets the applicable provisions of 14 CFR part 25, as amended by Amendments 25–1 through 25–129.

If the Administrator finds that the applicable airworthiness regulations (i.e., 14 CFR part 25) do not contain adequate or appropriate safety standards for the Model A350–900 series airplane because of a novel or unusual design feature, special conditions are prescribed under § 21.16.

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

The FAA issues special conditions, as defined in 14 CFR 11.19, under § 11.38, and they become part of the type-certification basis under § 21.17(a)(2).

In addition to the applicable airworthiness regulations and special conditions, the Model A350–900 series must comply with the fuel vent and exhaust emission requirements of 14 CFR part 34 and the noise certification requirements of 14 CFR part 36 and the FAA must issue a finding of regulatory adequacy under § 611 of Public Law 92–574, the ''Noise Control Act of 1972.''

Novel or Unusual Design Features

The Airbus Model A350–900 series airplane will incorporate the following novel or unusual design features: composite fuel tanks.

Discussion

The extensive use of composite materials in the design of the A350 wing and fuel tank structure is considered a major change from conventional and traditional methods of construction, as this will be only the second large transport category airplane to be certificated with this level of composite material for these purposes. The applicable airworthiness regulations do not contain specific standards for post-crash fire safety performance of wing and fuel tank skin or structure.

In order to provide the same level of safety as exists with conventional airplane construction, Airbus must demonstrate that the Model A350–900 series airplane has sufficient post-crash survivability to enable occupants to safely evacuate in the event that the wings are exposed to a large fuel-fed fire. Factors in fuel tank survivability

are the structural integrity of the wing and tank, flammability of the tank, burn-through resistance of the wing skin, and the presence of auto-ignition threats during exposure to a fire. The FAA assessed post-crash survival time during the adoption of Amendment 25–111 for fuselage burn-through protection. Studies conducted by and on behalf of the FAA indicated that, following a survivable accident, prevention of fuselage burn-through for approximately 5 minutes can significantly enhance survivability.[2]

There is little benefit in requiring the design to prevent wing skin burn-through beyond five minutes, due to the effects of the fuel fire itself on the rest of the airplane. That assessment was carried out based on accidents involving airplanes with conventional fuel tanks, and considering the ability of ground personnel to rescue occupants. In addition, AC 20–135 indicates that, when aluminum is used for fuel tanks, the tank should withstand the effects of fire for 5 minutes without failure. Therefore, to be consistent with existing capability and related requirements, the Model A350–900 series airplane fuel tanks must be capable of resisting a post-crash fire for at least 5 minutes. In demonstrating compliance, Airbus must address a range of fuel loads from minimum to maximum, as well as any other critical fuel load.

Applicability

As discussed above, these proposed special conditions apply to Airbus Model A350–900 series airplanes. Should Airbus apply later for a change to the type certificate to include another model incorporating the same novel or unusual design feature, the proposed special conditions would apply to that model as well under the provisions of § 21.101.

Conclusion

This action affects only certain novel or unusual design features on the Airbus Model A350–900 series airplanes. It is not a rule of general applicability.

List of Subjects in 14 CFR part 25

Aircraft, Aviation safety, Reporting and recordkeeping requirements.

The authority citation for these special conditions is as follows:

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

The Proposed Special Conditions

Accordingly, pursuant to the authority delegated to me by the Administrator, the following special conditions are proposed as part of the type certification basis for the Model A350–900 series airplane:

In addition to complying with 14 CFR part 25 regulations governing the fire-safety performance of the fuel tanks, wings, and nacelle, the Airbus Model A350–900 series airplane must demonstrate acceptable post-crash survivability in the event the wings are exposed to a large fuel-fed ground fire. Airbus must demonstrate that the wing and fuel tank design can endure an external fuel-fed pool fire for at least five minutes. This shall be demonstrated for minimum fuel loads (not less than reserve fuel levels) and maximum fuel loads (maximum range fuel quantities), and other identified critical fuel loads. Considerations shall include fuel tank flammability, burn-through resistance, wing structural strength retention properties, and auto-ignition threats during a ground fire event for the required time duration.

Issued in Renton, Washington, on October 22, 2013.

Stephen P. Boyd

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2014–00102 Filed 1–7–14; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 25

[Docket No. FAA–2013–0901; Notice No. 25–13–23–SC]

Special Conditions: Airbus, Model A350–900 Series Airplane; Flight Envelope Protection: High Speed Limiting

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed special conditions.

SUMMARY: This action proposes special conditions for Airbus Model A350–900 series airplanes. These airplanes will have a novel or unusual design feature associated with high speed limiting. The applicable airworthiness regulations do not contain adequate or appropriate safety standards for this design feature. These proposed special conditions contain the additional safety standards that the Administrator considers necessary to establish a level of safety equivalent to that established by the existing airworthiness standards.

DATES: Send your comments on or before February 7, 2014.

ADDRESSES: Send comments identified by docket number FAA–2013–0901 using any of the following methods:

- *Federal eRegulations Portal:* Go to *http://www.regulations.gov/* and follow the online instructions for sending your comments electronically.
- *Mail:* Send comments to Docket Operations, M–30, U.S. Department of Transportation (DOT), 1200 New Jersey Avenue SE., Room W12–140, West Building Ground Floor, Washington, DC 20590–0001.
- *Hand Delivery or Courier:* Take comments to Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE., Washington, DC., between 9 a.m. and 5 p.m., Monday through Friday, except federal holidays.
- *Fax:* Fax comments to Docket Operations at 202–493–2251.

Privacy: The FAA will post all comments it receives, without change, to *http://www.regulations.gov/,* including any personal information the commenter provides. Using the search function of the docket Web site, anyone can find and read the electronic form of all comments received into any FAA docket, including the name of the individual sending the comment (or signing the comment for an association, business, labor union, etc.). DOT's complete Privacy Act Statement can be found in the **Federal Register** published on April 11, 2000 (65 FR 19477–19478), as well as at *http://DocketsInfo.dot.gov/.*

Docket: Background documents or comments received may be read at *http://www.regulations.gov/* at any time. Follow the online instructions for accessing the docket or go to the Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except federal holidays.

FOR FURTHER INFORMATION CONTACT: Joe Jacobsen, FAA, Airplane and Flightcrew Interface Branch, ANM–111, Transport Airplane Directorate, Aircraft Certification Service, 1601 Lind Avenue SW., Renton, Washington 98057–3356; telephone (425) 227–2011; facsimile (425) 227–1320.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite interested people to take part in this rulemaking by sending

[2] Cherry, R. and Warren, K. ''Fuselage Burnthrough Protection for Increased Postcrash Occupant Survivability: Safety Benefit Analysis Based on Past Accidents, ''FAA Report DOT/FAA/AR–99/57, September 1999 and R G W Cherry & Associates Limited, ''A Benefit Analysis for Cabin Water Spray Systems and Enhanced Fuselage Burnthrough Protection,'' FAA Report DOT/FAA/AR–02/49, April 7, 2003.

written comments, data, or views. The most helpful comments reference a specific portion of the special conditions, explain the reason for any recommended change, and include supporting data.

We will consider all comments we receive on or before the closing date for comments. We may change these special conditions based on the comments we receive.

Background

On August 25, 2008, Airbus applied for a type certificate for their new Model A350–900 series airplane. Later, Airbus requested and the FAA approved an extension to the application for FAA type certification to June 28, 2009. The Model A350–900 series has a conventional layout with twin wing-mounted Rolls-Royce Trent engines. It features a twin aisle 9-abreast economy class layout, and accommodates side-by-side placement of LD–3 containers in the cargo compartment. The basic Model A350–900 series configuration will accommodate 315 passengers in a standard two-class arrangement. The design cruise speed is Mach 0.85 with a Maximum Take-Off Weight of 602,000 lbs. Airbus proposes the Model A350–900 series to be certified for extended operations (ETOPS) beyond 180 minutes at entry into service for up to a 420-minute maximum diversion time.

The longitudinal control law design of the Airbus Model A350–900 incorporates an overspeed protection system in the normal mode; this would prevent the pilot from inadvertently or intentionally exceeding a speed approximately equivalent to V_{FC} or attaining V_{DF}. Current Title 14 Code of Federal Regulations (14 CFR) part 25 sections do not relate to a high speed limiting protection system that might preclude or modify flying qualities assessments in the overspeed region. However, the requirements of § 25.253 (High-speed characteristics) and its related policy are applicable to the Model A350–900 series and not affected by this proposed special condition.

Type Certification Basis

Under Title 14, Code of Federal Regulations (14 CFR) 21.17, Airbus must show that the Model A350–900 series meets the applicable provisions of 14 CFR part 25, as amended by Amendments 25–1 through 25–129.

If the Administrator finds that the applicable airworthiness regulations (i.e., 14 CFR part 25) do not contain adequate or appropriate safety standards for the Airbus Model A350–900 series because of a novel or unusual design feature, special conditions are prescribed under § 21.16.

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

In addition to the applicable airworthiness regulations and proposed special conditions, the Model A350–900 series must comply with the fuel vent and exhaust emission requirements of 14 CFR part 34 and the noise certification requirements of 14 CFR part 36 and the FAA must issue a finding of regulatory adequacy under section 611 of Public Law 92–574, the ''Noise Control Act of 1972.''

The FAA issues special conditions, as defined in 14 CFR 11.19, under § 11.38, and they become part of the type-certification basis under § 21.17(a)(2).

Novel or Unusual Design Features

The Model A350–900 series will incorporate the following novel or unusual design features: An overspeed protection system which prevents the pilot from inadvertently or intentionally exceeding a speed approximately equivalent to V_{FC} or attaining V_{DF}.

At V_{MO} + 10 knots or M_{MO} + 0.02, an automatic nose up pitch is applied with phase advance in case of high acceleration. The speed stabilizes at $V_D - 10kts/M_D - 0.02$ if the stick is full forward, or the speed will return below V_{MO}/M_{MO} if the stick is released.

Discussion

This proposed special condition establishes requirements to ensure that operation of the high speed limiting protection system does not impede normal attainment of speeds up to the overspeed warning. Its main features are:

1. It protects the airplane against high speed/high Mach number flight conditions beyond V_{MO}/M_{MO}.
2. It does not interfere with flight at V_{MO}/M_{MO}, even in turbulent air.
3. It still provides load factor limitation through the ''pitch limiting'' function described below.
4. It restores positive static stability beyond V_{MO}/M_{MO}.

Applicability

As discussed above, these proposed special conditions apply to Airbus Model A350–900 series airplanes. Should Airbus apply later for a change to the type certificate to include another model incorporating the same novel or unusual design feature, the proposed special conditions would apply to that model as well.

Conclusion

This action affects only certain novel or unusual design features on the Airbus Model A350–900 series airplanes. It is not a rule of general applicability.

List of Subjects in 14 CFR Part 25

Aircraft, Aviation safety, Reporting and recordkeeping requirements.

The authority citation for these special conditions is as follows:

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

The Proposed Special Conditions

Accordingly, the Federal Aviation Administration (FAA) proposes the following special condition as part of the type certification basis for Airbus Model A350–900 series airplanes.

In addition to § 25.143, the following requirements apply: Operation of the high speed limiter during all routine and descent procedure flight must not impede normal attainment of speeds up to overspeed warning

Issued in Renton, Washington, on October 22, 2013.

Stephen P. Boyd,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2014–00100 Filed 1–7–14; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 25

[Docket No. FAA–2013–0892; Notice No. 25–13–21–SC]

Special Conditions: Airbus, A350–900 Series Airplane; Crashworthiness—Emergency Landing Conditions

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed special conditions.

SUMMARY: This action proposes special conditions for the Airbus Model A350–900 series airplanes. These airplanes will have a novel or unusual design feature associated with crashworthiness of carbon fiber reinforced plastic used in the construction of the fuselage. The applicable airworthiness regulations do not contain adequate or appropriate safety standards for this design feature. These proposed special conditions contain the additional safety standards that the Administrator considers

necessary to establish a level of safety equivalent to that established by the existing airworthiness standards.

DATES: Send your comments on or before February 24, 2014.

ADDRESSES: Send comments identified by docket number FAA–2013–0892 using any of the following methods:

- *Federal eRegulations Portal:* Go to *http://www.regulations.gov/* and follow the online instructions for sending your comments electronically.
- *Mail:* Send comments to Docket Operations, M–30, U.S. Department of Transportation (DOT), 1200 New Jersey Avenue SE., Room W12–140, West Building Ground Floor, Washington, DC, 20590–0001.
- *Hand Delivery or Courier:* Take comments to Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except federal holidays.
- *Fax:* Fax comments to Docket Operations at 202–493–2251.

Privacy: The FAA will post all comments it receives, without change, to *http://www.regulations.gov/*, including any personal information the commenter provides. Using the search function of the docket Web site, anyone can find and read the electronic form of all comments received into any FAA docket, including the name of the individual sending the comment (or signing the comment for an association, business, labor union, etc.). DOT's complete Privacy Act Statement can be found in the **Federal Register** published on April 11, 2000 (65 FR 19477–19478), as well as at *http://DocketsInfo.dot.gov/.*

Docket: Background documents or comments received may be read at *http://www.regulations.gov/* at any time. Follow the online instructions for accessing the docket or go to the Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except federal holidays.

FOR FURTHER INFORMATION CONTACT: Todd Martin, FAA, Airframe/Cabin Safety, ANM–115, Transport Airplane Directorate, Aircraft Certification Service, 1601 Lind Avenue SW., Renton, Washington, 98057–3356; telephone (425) 227–1178; facsimile (425) 227–1320.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite interested people to take part in this rulemaking by sending written comments, data, or views. The most helpful comments reference a specific portion of the proposed special conditions, explain the reason for any recommended change, and include supporting data. We ask that you send us two copies of written comments.

We will consider all comments we receive on or before the closing date for comments. We may change these proposed special conditions based on the comments we receive.

Background

On August 25, 2008, Airbus applied for a type certificate for their new Model A350–900 series airplane. Later, Airbus requested and the FAA approved an extension to the application for FAA type certification to June 28, 2009, The Model A350–900 series has a conventional layout with twin wing-mounted Rolls-Royce Trent XWB engines. It features a twin aisle 9-abreast economy class layout, and accommodates side-by-side placement of LD–3 containers in the cargo compartment. The basic Model A350–900 series configuration will accommodate 315 passengers in a standard two-class arrangement. The design cruise speed is Mach 0.85 with a Maximum Take-Off Weight of 602,000 lbs. Airbus proposes the Model A350–900 series to be certified for extended operations (ETOPS) beyond 180 minutes at entry into service for up to a 420-minute maximum diversion time.

Changes in the structural behavior of the Airbus Model A350–900 series airplanes compared to currently certificated designs could degrade the survivability of Model A350–900 series occupants in crash conditions that are within the limits of survivability for other designs.

There is no aircraft-level survivable crash condition specified in the airworthiness regulations, and metallic aircraft have not been specifically designed against survivable impact conditions. However, the structural behavior of previously certificated aircraft in a survivable crash event and the associated limits are considered generally acceptable. It is therefore reasonable to expect that a design using new materials, such as the Model A350–900 series airplanes use, should be assessed to ensure that the material meets the currently accepted level of safety. The FAA and industry have collected a significant amount of experimental data as well as data from crashes of transport category airplanes that show a high occupant survival rate at vertical descent velocities up to 30 ft/sec. Based on this information, the FAA finds it appropriate and necessary for an assessment of the Model A350–900 series airplanes to span a range of airplane vertical descent speeds up to 30 ft/sec.

Type Certification Basis

Under Title 14, Code of Federal Regulations (14 CFR) 21.17, Airbus must show that the Model A350–900 series meets the applicable provisions of 14 CFR part 25, as amended by Amendments 25–1 through 25–129.

If the Administrator finds that the applicable airworthiness regulations (i.e., 14 CFR part 25) do not contain adequate or appropriate safety standards for the Model A350–900 series because of a novel or unusual design feature, special conditions are prescribed under § 21.16.

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

In addition to the applicable airworthiness regulations and special conditions, the Model A350–900 series must comply with the fuel vent and exhaust emission requirements of 14 CFR part 34 and the noise certification requirements of 14 CFR part 36 and the FAA must issue a finding of regulatory adequacy under § 611 of Public Law 92–574, the ''Noise Control Act of 1972.''

The FAA issues special conditions, as defined in 14 CFR 11.19, under § 11.38, and they become part of the type-certification basis under § 21.17(a)(2).

Novel or Unusual Design Features

The Airbus Model A350–900 series will incorporate the following novel or unusual design feature: fuselage fabricated with a combination of carbon fiber reinforced plastic (CFRP) and metallic structure. This is a novel and unusual design feature for a large transport airplane. Structure fabricated from CFRP may behave differently than metallic structure in crash conditions because of differences in material ductility, stiffness, failure modes, and energy absorption characteristics. Therefore, the impact response characteristics of the Model A350–900 series airplane must be evaluated to ensure that its survivable crashworthiness characteristics provide at least the same level of safety as those of a similarly sized airplane constructed from traditionally used metallic materials.

There are no existing regulations that adequately address this potential difference in impact response

characteristics for what are considered survivable crash conditions. The proposed special conditions are necessary to ensure a level of safety equivalent to that provided by 14 CFR part 25.

Discussion

Factors in crash survivability are retention of items of mass, maintenance of occupant emergency egress paths, maintenance of acceptable acceleration and loads experienced by the occupants, and maintenance of a survivable volume. To provide the same level of safety as exists with conventional airplane construction, Airbus should show that the Model A350–900 series airplanes have sufficient crashworthiness capabilities under foreseeable survivable impact events. To show this, Airbus should evaluate the impact response characteristics of the Model A350–900 series airplane to ensure that its crashworthiness characteristics are not significantly different from those of a similarly sized airplane built from traditionally used metallic materials.

In their evaluation of the Model A350–900 series airplane response to an impact event, Airbus should demonstrate that the structural behavior is similar to that expected from a metallic airframe of similar size to the Model A350–900, or incorporate mitigating design features that provide a similar level of safety.

Airbus should demonstrate either through analysis using validated analytical tools or by direct test evidence that the crash dynamics of the A350 fuselage structure provides a level of occupant protection consistent with previously certificated large transport category airplanes.

Applicability

As discussed above, these proposed special conditions apply to Airbus Model A350–900 series airplanes. Should Airbus apply later for a change to the type certificate to include another model incorporating the same novel or unusual design feature, the proposed special conditions would apply to that model as well.

Conclusion

This action affects only certain novel or unusual design features on the Airbus Model A350–900 series airplanes. It is not a rule of general applicability.

List of Subjects in 14 CFR Part 25

Aircraft, Aviation safety, Reporting and recordkeeping requirements.

The authority citation for these special conditions is as follows:

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

The Proposed Special Conditions

Accordingly, the Federal Aviation Administration (FAA) proposes the following special conditions as part of the type certification basis for Airbus Model A350–900 series airplanes.

The Airbus Model A350–900 series airplanes must provide an equivalent level of occupant safety and survivability to that provided by previously certificated wide-body transports of similar size under foreseeable survivable impact events for the following four criteria. In order to demonstrate an equivalent level of occupant safety and survivability, the applicant must demonstrate that Model A350–900 series airplanes meet the following criteria for a range of airplane vertical descent velocities up to 30 ft/sec.

1. Retention of items of mass. The occupants, i.e., passengers, flight attendants, and flightcrew, must be protected during the impact event from release of seats, overhead bins, and other items of mass due to the impact loads and resultant structural deformation of the supporting airframe and floor structures. The applicant must show that loads due to the impact event and resultant structural deformation of the supporting airframe and floor structure at the interface of the airplane structure to seats, overhead bins, and other items of mass are comparable to those of previously certificated wide-body transports of similar size for the range of descent velocities stated above. The attachments of these items need not be designed for static emergency landing loads in excess of those defined in § 25.561 if impact response characteristics of the Airbus Model A350–900 series airplanes yield load factors at the attach points that are comparable to those for a previously certificated wide-body transport category airplane.

2. Maintenance of acceptable acceleration and loads experienced by the occupants. The applicant must show that the impact response characteristics of the Airbus Model A350–900 series airplane, specifically the vertical acceleration levels experienced at the seat/floor interface and loads experienced by the occupants during the impact events, are consistent with those found in § 25.562(b) or with levels expected for a previously certificated wide-body transport category airplane for the conditions stated above.

3. Maintenance of a survivable volume. For the conditions stated above, the applicant must show that all areas of the airplane occupied for takeoff and landing provide a survivable volume comparable to that of previously certificated wide-body transports of similar size during and after the impact event. This means that structural deformation will not result in infringement of the occupants' normal living space so that passenger survivability will not be significantly affected.

4. Maintenance of occupant emergency egress paths. The evacuation of occupants must be comparable to that from a previously certificated wide-body transport of similar size. To show this, the applicant must show that the suitability of the egress paths, as determined following the vertical impact events, is comparable to the suitability of the egress paths of a comparable, certificated wide-body transport, as determined following the same vertical impact events.

Issued in Renton, Washington, on October 22, 2013.

Stephen P. Boyd,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2014–00104 Filed 1–7–14; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 25

[Docket No. FAA–2013–0911; Notice No. 25–13–22–SC]

Special Conditions: Airbus, Model A350–900 Series Airplane; Lateral Trim Function Through Differential Flap Setting

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed special conditions.

SUMMARY: This action proposes special conditions for the Airbus Model A350–900 series airplanes. These airplanes will have a novel or unusual design feature associated with a lateral trim function that deploys flaps asymmetrically for airplane lateral trim control. This function replaces the traditional method of providing airplane lateral trim over a small range through flap and aileron mechanical rigging. The applicable airworthiness regulations do not contain adequate or appropriate safety standards for this design feature. These proposed special conditions contain the additional safety standards that the Administrator considers necessary to establish a level of safety

equivalent to that established by the existing airworthiness standards.

DATES: Send your comments on or before February 24, 2014.

ADDRESSES: Send comments identified by docket number FAA–2013–0911 using any of the following methods:

- *Federal eRegulations Portal:* Go to *http://www.regulations.gov/* and follow the online instructions for sending your comments electronically.
- *Mail:* Send comments to Docket Operations, M–30, U.S. Department of Transportation (DOT), 1200 New Jersey Avenue SE., Room W12–140, West Building Ground Floor, Washington, DC 20590–0001.
- *Hand Delivery or Courier:* Take comments to Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except federal holidays.
- *Fax:* Fax comments to Docket Operations at 202–493–2251.

Privacy: The FAA will post all comments it receives, without change, to *http://www.regulations.gov/*, including any personal information the commenter provides. Using the search function of the docket Web site, anyone can find and read the electronic form of all comments received into any FAA docket, including the name of the individual sending the comment (or signing the comment for an association, business, labor union, etc.). DOT's complete Privacy Act Statement can be found in the **Federal Register** published on April 11, 2000 (65 FR 19477–19478), as well as at *http://DocketsInfo.dot.gov/.*

Docket: Background documents or comments received may be read at *http://www.regulations.gov/* at any time. Follow the online instructions for accessing the docket or go to the Docket Operations in Room W12–140 of the West Building Ground Floor at 1200 New Jersey Avenue SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except federal holidays.

FOR FURTHER INFORMATION CONTACT: Robert C. Jones, FAA, Propulsion/Mechanical Systems, ANM–112, Transport Airplane Directorate, Aircraft Certification Service, 1601 Lind Avenue SW., Renton, Washington 98057–3356; telephone (425) 227–1234; facsimile (425) 227–1320.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite interested people to take part in this rulemaking by sending written comments, data, or views. The most helpful comments reference a specific portion of the special conditions, explain the reason for any recommended change, and include supporting data.

We will consider all comments we receive on or before the closing date for comments. We may change these proposed special conditions based on the comments we receive.

Background

On August 25, 2008, Airbus applied for a type certificate for their new Model A350–900 series airplane. Later, Airbus requested and the FAA approved an extension to the application for FAA type certification to June 28, 2009. The Model A350–900 series has a conventional layout with twin wing-mounted Rolls-Royce Trent XWB engines. It features a twin aisle 9-abreast economy class layout, and accommodates side-by-side placement of LD–3 containers in the cargo compartment. The basic Model A350–900 series configuration will accommodate 315 passengers in a standard two-class arrangement. The design cruise speed is Mach 0.85 with a Maximum Take-Off Weight of 602,000 lbs. Airbus proposes the Model A350–900 series to be certified for extended operations (ETOPS) beyond 180 minutes at entry into service for up to a 420-minute maximum diversion time.

On conventional airplanes, small lateral airplane asymmetries have typically been addressed through flap and aileron rigging (e.g., using shims). On Model A350–900 series airplanes, an order for asymmetric flap deployment will be computed by the primary flight control system as a function of the aileron position. The current airworthiness standards do not contain adequate safety standards for asymmetric use of the flaps as proposed for Airbus Model A350–900 series airplanes. Special conditions are needed to account for the aspects of a function used to command an intended flap asymmetry. The lateral trim function is intended to be performed once during climb and once during cruise to compensate for small airplane lateral asymmetries.

The lateral trim function is not a trim control system in the conventional sense as it has no pilot interface and is not governed by § 25.677. In fact some fly-by-wire airplanes have no pilot operated lateral trim at all. The lateral trim function is simply an additional fly-by-wire flight control function that nulls small roll asymmetries in certain flight phases with small asymmetric flap deployments. Although the function operates under normal conditions within the small range of the traditional rigging, there may be failure cases leading to a significant out of range asymmetric flap condition. An asymmetry threshold will protect the system against excessive flap asymmetry.

Type Certification Basis

Under Title 14, Code of Federal Regulations (14 CFR) 21.17, Airbus must show that the Model A350–900 series meets the applicable provisions of 14 CFR part 25, as amended by Amendments 25–1 through 25–129.

If the Administrator finds that the applicable airworthiness regulations (i.e., 14 CFR part 25) do not contain adequate or appropriate safety standards for the Model A350–900 series because of a novel or unusual design feature, special conditions are prescribed under § 21.16.

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

In addition to the applicable airworthiness regulations and proposed special conditions, the Model A350–900 series must comply with the fuel vent and exhaust emission requirements of 14 CFR part 34 and the noise certification requirements of 14 CFR part 36 and the FAA must issue a finding of regulatory adequacy under § 611 of Public Law 92–574, the ''Noise Control Act of 1972.''

The FAA issues special conditions, as defined in 14 CFR 11.19, under § 11.38, and they become part of the type-certification basis under § 21.17(a)(2).

Novel or Unusual Design Features

The Airbus Model A350–900 series will incorporate the following novel or unusual design features: the asymmetric use of flaps to address lateral trim which is not adequately addressed by § 25.701.

Discussion

Title 14 Code of Federal Regulations (14 CFR) part 25 § 25.701(a) requires that unless the airplane has safe flight characteristics with the flaps or slats retracted on one side and extended on the other, flap and slat surfaces must be synchronized by either a mechanical interconnection or any equivalent means that has the same integrity. Synchronization is interpreted to mean that flap movement is symmetrical throughout the full range of flap motion. Because the lateral trim function

intentionally creates asymmetric flap motions, the flap system installation of the Model A350–900 series does not meet the requirement of § 25.701(a) and (d).

Applicability

As discussed above, these proposed special conditions apply to Airbus Model A350–900 series airplanes. Should Airbus apply later for a change to the type certificate to include another model incorporating the same novel or unusual design feature, the proposed special conditions would apply to that model as well.

Conclusion

This action affects only certain novel or unusual design features on the Airbus Model A350–900 series airplanes. It is not a rule of general applicability.

List of Subjects in 14 CFR Part 25

Aircraft, Aviation safety, Reporting and recordkeeping requirements.

The authority citation for these special conditions is as follows:

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

The Proposed Special Conditions

Accordingly, the Federal Aviation Administration (FAA) proposes the following special conditions as part of the type certification basis for Airbus Model A350–900 series airplanes.

1. Lateral Trim Function through Differential Flap Setting.

Current airworthiness standards, specifically § 25.701, do not contain adequate safety standards for the proposed design. In lieu of the requirements of § 25.701(a) and (d) for the lateral trim function, the following special condition is proposed:

a. Airbus must demonstrate that an unsafe condition is not created by using the flaps asymmetrically,

b. The degree of acceptable asymmetry must be defined and justified for all flight phases with respect to:

- § 25.701(b) and (c), with the worst case asymmetric flap configurations, and
- providing equivalent protection against excess asymmetry in the same manner as § 25.701 provides to systems that are synchronized or use another equivalent means to prevent asymmetry.

c. This lateral trim function is a flight control system and therefore must show compliance to both general system requirements as well as general flight control requirements. Therefore, the function must be demonstrated not to embody, where practicable, significant latent failures.

Issued in Renton, Washington, on October 22, 2013.

Stephen P. Boyd,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2014–00105 Filed 1–7–14; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2013–0175; Airspace Docket No. 13–AGL–12]

Proposed Amendment of Class D and Class E Airspace; Traverse City, MI

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This action proposes to amend Class D and Class E airspace at Traverse City, MI. Additional controlled airspace is necessary to accommodate new Standard Instrument Approach Procedures (SIAP) at Cherry Capital Airport. Geographic coordinates of the airport also would be adjusted. The FAA is taking this action to enhance the safety and management of Instrument Flight Rules (IFR) operations for SIAPs at the airport.

DATES: Comments must be received on or before February 24, 2014.

ADDRESSES: Send comments on this proposal to the U.S. Department of Transportation, Docket Operations, 1200 New Jersey Avenue SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–0001. You must identify the docket number FAA–2013–0175/Airspace Docket No. 13–AGL–12, at the beginning of your comments. You may also submit comments through the Internet at *http://www.regulations.gov.* You may review the public docket containing the proposal, any comments received, and any final disposition in person in the Dockets Office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Docket Office (telephone 1–800–647–5527), is on the ground floor of the building at the above address.

FOR FURTHER INFORMATION CONTACT: Scott Enander, Central Service Center, Operations Support Group, Federal Aviation Administration, Southwest Region, 2601 Meacham Blvd., Fort Worth, TX 76137; telephone: (817) 321–7716.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested parties are invited to participate in this proposed rulemaking by submitting such written data, views, or arguments, as they may desire. Comments that provide the factual basis supporting the views and suggestions presented are particularly helpful in developing reasoned regulatory decisions on the proposal. Comments are specifically invited on the overall regulatory, aeronautical, economic, environmental, and energy-related aspects of the proposal. Communications should identify both docket numbers and be submitted in triplicate to the address listed above. Commenters wishing the FAA to acknowledge receipt of their comments on this notice must submit with those comments a self-addressed, stamped postcard on which the following statement is made: ''Comments to Docket No. FAA–2013–0175/Airspace Docket No. 13–AGL–12.'' The postcard will be date/time stamped and returned to the commenter.

Availability of NPRMs

An electronic copy of this document may be downloaded through the Internet at *http://www.regulations.gov.* Recently published rulemaking documents can also be accessed through the FAA's Web page at *http://www.faa.gov/airports_airtraffic/air_traffic/publications/airspace_amendments/.*

You may review the public docket containing the proposal, any comments received and any final disposition in person in the Dockets Office (see **ADDRESSES** section for address and phone number) between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. An informal docket may also be examined during normal business hours at the office of the Central Service Center, 2601 Meacham Blvd., Fort Worth, TX 76137.

Persons interested in being placed on a mailing list for future NPRMs should contact the FAA's Office of Rulemaking (202) 267–9677, to request a copy of Advisory Circular No. 11–2A, Notice of Proposed Rulemaking Distribution System, which describes the application procedure.

The Proposal

This action proposes to amend Title 14, Code of Federal Regulations (14 CFR), part 71 by amending Class D airspace, Class E airspace designated as a surface area, and Class E airspace extending upward from 700 feet above the surface to accommodate new standard instrument approach

procedures at Cherry Capital Airport, Traverse City, MI. Accordingly, an additional segment to the Class D airspace and Class E surface area would extend from the 4.4-mile radius of the airport to 5.3 miles south of the airport, and an additional segment to the Class E transition area would extend from the 7.7-mile radius of the airport to 10.3 miles south of the airport, to retain the safety and management of IFR aircraft in Class D and Class E airspace to/from the en route environment. Geographic coordinates would also be updated to coincide with the FAA's aeronautical database.

Class D and Class E airspace areas are published in Paragraphs 5000, 6002 and 6005, respectively, of FAA Order 7400.9X, dated August 7, 2013 and effective September 15, 2013, which is incorporated by reference in 14 CFR 71.1. The Class D and Class E airspace designations listed in this document will be published subsequently in the Order.

The FAA has determined that this proposed regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore, (1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the U.S. Code. Subtitle 1, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority. This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it would amend controlled airspace at Cherry Capital Airport, Traverse City, MI.

Environmental Review

This proposal will be subject to an environmental analysis in accordance with FAA Order 1050.1E, ''Environmental Impacts: Policies and Procedures'' prior to any FAA final regulatory action.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

The Proposed Amendment

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

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

■ The authority citation for part 71 continues to read as follows:

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

§ 71.1 [Amended]

■ The incorporation by reference in 14 CFR 71.1 of FAA Order 7400.9X, Airspace Designations and Reporting Points, dated August 7, 2013, and effective September 15, 2013, is amended as follows:

Paragraph 5000 Class D Airspace.

* * * * *

AGL MI D Traverse City, MI [Amended]

Traverse City, Cherry Capital Airport, MI
(Lat. 44°44′30″ N., long. 85°34′57″ W.)

That airspace extending upward from the surface to and including 3,100 feet MSL within a 4.4-mile radius of Cherry Capital Airport, and within 1 mile each side of the 180° bearing from the airport extending from the 4.4-mile radius to 5.3 miles south of the airport. This Class D airspace area is effective during the specific dates and times established in advance by a Notice to Airmen. The effective date and time will thereafter be continuously published in the Airport/Facility Directory.

Paragraph 6002 Class E Airspace designated as a surface area.

* * * * *

AGL MI E2 Traverse City, MI [Amended]

Traverse City, Cherry Capital Airport, MI
(Lat. 44°44′30″ N., long. 85°34′57″ W.)

Within a 4.4-mile radius of Cherry Capital Airport, and within 1 mile each side of the 180° bearing from the airport extending from the 4.4-mile radius to 5.3 miles south of the airport. This Class E airspace area is effective during the specific dates and times established in advance by a Notice to Airmen. The effective date and time will thereafter be continuously published in the Airport/Facility Directory.

Paragraph 6005 Class E Airspace areas extending upward from 700 feet or more above the surface of the earth.

* * * * *

AGL MI E5 Traverse City, MI [Amended]

Traverse City, Cherry Capital Airport, MI
(Lat. 44°44′30″ N., long. 85°34′57″ W.)
Traverse City VORTAC
(Lat. 44°44′04″ N., long. 85°33′00″ W.)
Point in Space Coordinates
(Lat. 44°39′08″ N., long. 85°35′17″ W.)

That airspace extending upward from 700 feet the surface within a 7.7-mile radius of Cherry Capital Airport, and within 4 miles west and 8 miles east of the Traverse City VORTAC 158° radial extending from the 7.7-mile radius to 14.4 miles south of the airport, and within 3.2 miles west of the 169° bearing from the point in space extending from the 7.7-mile radius to 9 miles south of the airport, and within 2 miles each side of the 180° bearing from the airport extending from the 7.7-mile radius to 10.3 miles south of the airport.

Issued in Fort Worth, TX, on December 18, 2013.

David P. Medina,

Manager, Operations Support Group, ATO Central Service Center.

[FR Doc. 2014–00106 Filed 1–7–14; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2013–0587; Airspace Docket No. 13–ACE–8]

Proposed Amendment of Class E Airspace; Jefferson City, MO

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This action proposes to amend Class E airspace at Jefferson City, MO. Decommissioning of the Noah non-directional radio beacon (NDB) at Jefferson City Memorial Airport has made reconfiguration necessary for standard instrument approach procedures and for the safety and management of Instrument Flight Rules (IFR) operations at the airport.

DATES: 0901 UTC. Comments must be received on or before February 24, 2014.

ADDRESSES: Send comments on this proposal to the U.S. Department of Transportation, Docket Operations, 1200 New Jersey Avenue SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–0001. You must identify the docket number FAA–2013–0587/Airspace Docket No. 13–ACE–8, at

the beginning of your comments. You may also submit comments through the Internet at *http://www.regulations.gov.* You may review the public docket containing the proposal, any comments received, and any final disposition in person in the Dockets Office between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The Docket Office (telephone 1–800–647–5527), is on the ground floor of the building at the above address.

FOR FURTHER INFORMATION CONTACT: Scott Enander, Central Service Center, Operations Support Group, Federal Aviation Administration, Southwest Region, 2601 Meacham Blvd., Fort Worth, TX 76137; telephone: (817) 321–7716.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested parties are invited to participate in this proposed rulemaking by submitting such written data, views, or arguments, as they may desire. Comments that provide the factual basis supporting the views and suggestions presented are particularly helpful in developing reasoned regulatory decisions on the proposal. Comments are specifically invited on the overall regulatory, aeronautical, economic, environmental, and energy-related aspects of the proposal. Communications should identify both docket numbers and be submitted in triplicate to the address listed above. Commenters wishing the FAA to acknowledge receipt of their comments on this notice must submit with those comments a self-addressed, stamped postcard on which the following statement is made: ''Comments to Docket No. FAA–2013–0587/Airspace Docket No. 13–ACE–8.'' The postcard will be date/time stamped and returned to the commenter.

Availability of NPRMs

An electronic copy of this document may be downloaded through the Internet at *http://www.regulations.gov.* Recently published rulemaking documents can also be accessed through the FAA's Web page at *http://www.faa.gov/airports_airtraffic/air_traffic/publications/airspace_amendments/.*

You may review the public docket containing the proposal, any comments received and any final disposition in person in the Dockets Office (see **ADDRESSES** section for address and phone number) between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. An informal docket may also be examined during normal business hours at the office of the Central Service Center, 2601 Meacham Blvd., Fort Worth, TX 76137.

Persons interested in being placed on a mailing list for future NPRMs should contact the FAA's Office of Rulemaking (202) 267–9677, to request a copy of Advisory Circular No. 11–2A, Notice of Proposed Rulemaking Distribution System, which describes the application procedure.

The Proposal

This action proposes to amend Title 14, Code of Federal Regulations (14 CFR), Part 71 by modifying Class E airspace extending upward from 700 feet above the surface for standard instrument approach procedures at Jefferson City Memorial Airport, Jefferson City, MO. Airspace reconfiguration is necessary due to the decommissioning of the Noah NDB and the cancellation of the NDB approach. The segment northwest of the airport would now be within 3.2 miles each side of the 303° bearing from the airport extending from the 6.6-mile radius to 14.3 miles. Controlled airspace is necessary for the safety and management of IFR operations at the airport.

Class E airspace areas are published in Paragraph 6005 of FAA Order 7400.9X, dated August 7, 2013 and effective September 15, 2013, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designation listed in this document would be published subsequently in the Order.

The FAA has determined that this proposed regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore, (1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the U.S. Code. Subtitle 1, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority. This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it would amend controlled airspace at Jefferson City Memorial Airport, Jefferson City, MO.

Environmental Review

This proposal will be subject to an environmental analysis in accordance with FAA Order 1050.1E, ''Environmental Impacts: Policies and Procedures'' prior to any FAA final regulatory action.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

The Proposed Amendment

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

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

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

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

§ 71.1 [Amended]

■ 2. The incorporation by reference in 14 CFR 71.1 of FAA Order 7400.9X, Airspace Designations and Reporting Points, dated August 7, 2013, and effective September 15, 2013, is amended as follows:

Paragraph 6005 Class E Airspace areas extending upward from 700 feet or more above the surface of the earth.

* * * * *

ACE MO E5 Jefferson City, MO [Amended]

Jefferson City Memorial Airport, MO
(Lat. 38°35′28″ N., long. 92°09′22″ W.)
Jefferson City Memorial Airport ILS
(Lat. 38°35′47″ N., long. 92°09′55″ W.)

That airspace extending upward from 700 feet above the surface within a 6.6-mile radius of Jefferson City Memorial Airport, and within 3.2 miles each side of the 303° bearing from the airport extending from the 6.6-mile radius to 14.3 miles northwest of the airport, and within 4 miles each side of the Jefferson City Memorial Airport ILS localizer course extending from the 6.6-mile radius to 11.8 miles southeast of the airport.

Issued in Fort Worth, TX, on December 18, 2013.

David P. Medina,

Manager, Operations Support Group, ATO Central Service Center.

[FR Doc. 2014–00107 Filed 1–7–14; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2013–0588; Airspace Docket No. 13–ASW–12]

Proposed Amendment of Class E Airspace; Paragould, AR

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This action proposes to amend Class E airspace at Paragould, AR. Decommissioning of the Paragould non-directional radio beacon (NDB) at Kirk Field has made reconfiguration necessary for standard instrument approach procedures and for the safety and management of Instrument Flight Rules (IFR) operations at the airport. Geographic coordinates also would be updated.

DATES: 0901 UTC. Comments must be received on or before February 24, 2014.

ADDRESSES: Send comments on this proposal to the U.S. Department of Transportation, Docket Operations, 1200 New Jersey Avenue SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–0001. You must identify the docket number FAA–2013–0588/Airspace Docket No. 13–ASW–12, at the beginning of your comments. You may also submit comments through the Internet at *http://www.regulations.gov.* You may review the public docket containing the proposal, any comments received, and any final disposition in person in the Dockets Office between 9:00 a.m. and 5:00 p.m., Monday through Friday, except Federal holidays. The Docket Office (telephone 1–800–647–5527), is on the ground floor of the building at the above address.

FOR FURTHER INFORMATION CONTACT: Scott Enander, Central Service Center, Operations Support Group, Federal Aviation Administration, Southwest Region, 2601 Meacham Blvd., Fort Worth, TX 76137; telephone: (817) 321–7716.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested parties are invited to participate in this proposed rulemaking by submitting such written data, views, or arguments, as they may desire. Comments that provide the factual basis supporting the views and suggestions presented are particularly helpful in developing reasoned regulatory decisions on the proposal. Comments are specifically invited on the overall regulatory, aeronautical, economic, environmental, and energy-related aspects of the proposal. Communications should identify both docket numbers and be submitted in triplicate to the address listed above. Commenters wishing the FAA to acknowledge receipt of their comments on this notice must submit with those comments a self-addressed, stamped postcard on which the following statement is made: ''Comments to Docket No. FAA–2013–0588/Airspace Docket No. 13–ASW–12.'' The postcard will be date/time stamped and returned to the commenter.

Availability of NPRMs

An electronic copy of this document may be downloaded through the Internet at *http://www.regulations.gov*. Recently published rulemaking documents can also be accessed through the FAA's Web page at *http://www.faa.gov/airports_airtraffic/air_traffic/publications/airspace_amendments/.*

You may review the public docket containing the proposal, any comments received and any final disposition in person in the Dockets Office (see **ADDRESSES** section for address and phone number) between 9:00 a.m. and 5:00 p.m., Monday through Friday, except Federal holidays. An informal docket may also be examined during normal business hours at the office of the Central Service Center, 2601 Meacham Blvd., Fort Worth, TX 76137.

Persons interested in being placed on a mailing list for future NPRMs should contact the FAA's Office of Rulemaking (202) 267–9677, to request a copy of Advisory Circular No. 11–2A, Notice of Proposed Rulemaking Distribution System, which describes the application procedure.

The Proposal

This action proposes to amend Title 14, Code of Federal Regulations (14 CFR), Part 71 by modifying Class E airspace extending upward from 700 feet above the surface for standard instrument approach procedures at Kirk Field, Paragould, AR. Airspace reconfiguration is necessary due to the decommissioning of the Paragould NDB and the cancellation of the NDB approach. The segment northeast of the airport would now be within 2.5 miles each side of the 062° bearing from the airport. Controlled airspace is necessary for the safety and management of IFR operations at the airport. Geographic coordinates would also be adjusted to coincide with the FAA's aeronautical database.

Class E airspace areas are published in Paragraph 6005 of FAA Order 7400.9X, dated August 7, 2013 and effective September 15, 2013, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designation listed in this document would be published subsequently in the Order.

The FAA has determined that this proposed regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore, (1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the U.S. Code. Subtitle 1, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority. This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it would amend controlled airspace at Kirk Field, Paragould, AR.

Environmental Review

This proposal will be subject to an environmental analysis in accordance with FAA Order 1050.1E, ''Environmental Impacts: Policies and Procedures'' prior to any FAA final regulatory action.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

The Proposed Amendment

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

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

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

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

§ 71.1 [Amended]

■ 2. The incorporation by reference in 14 CFR 71.1 of FAA Order 7400.9X, Airspace Designations and Reporting Points, dated August 7, 2013, and effective September 15, 2013, is amended as follows:

Paragraph 6005 Class E Airspace areas extending upward from 700 feet or more above the surface of the earth.

* * * * *

ASW AR E5 Paragould, AR [Amended]

Paragould, Kirk Field, AR

(Lat. 36°03′50″ N., long. 90°30′33″ W.)

That airspace extending upward from 700 feet above the surface within a 6.4-mile radius of Kirk Field, and within 2.5 miles each side of the 218° bearing from the airport extending from the 6.4-mile radius to 9.5 miles southwest of the airport, and within 2.5 miles each side of the 062° bearing from the airport extending from the 6.4-mile radius to 7.5 miles northeast of the airport.

Issued in Fort Worth, TX, on December 18, 2013.

David P. Medina,

Manager, Operations Support Group, ATO Central Service Center.

[FR Doc. 2014–00116 Filed 1–7–14; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2013–0596; Airspace Docket No. 13–ACE–11]

Proposed Amendment of Class E Airspace; Holdrege, NE

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This action proposes to amend Class E airspace at Holdrege, NE. Decommissioning of the Holdrege non-directional radio beacon (NDB) at Brewster Field Airport has made airspace reconfiguration necessary for standard instrument approach procedures and for the safety and management of Instrument Flight Rules (IFR) operations at the airport. Geographic coordinates also would be adjusted.

DATES: 0901 UTC. Comments must be received on or before February 24, 2014.

ADDRESSES: Send comments on this proposal to the U.S. Department of Transportation, Docket Operations, 1200 New Jersey Avenue SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–0001. You must identify the docket number FAA–2013–0596/Airspace Docket No. 13–ACE–11, at the beginning of your comments. You may also submit comments through the Internet at *http://www.regulations.gov.* You may review the public docket containing the proposal, any comments received, and any final disposition in person in the Dockets Office between 9:00 a.m. and 5:00 p.m., Monday through Friday, except Federal holidays. The Docket Office (telephone 1–800–647–5527), is on the ground floor of the building at the above address.

FOR FURTHER INFORMATION CONTACT: Scott Enander, Central Service Center, Operations Support Group, Federal Aviation Administration, Southwest Region, 2601 Meacham Blvd., Fort Worth, TX 76137; telephone: (817) 321–7716.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested parties are invited to participate in this proposed rulemaking by submitting such written data, views, or arguments, as they may desire. Comments that provide the factual basis supporting the views and suggestions presented are particularly helpful in developing reasoned regulatory decisions on the proposal. Comments are specifically invited on the overall regulatory, aeronautical, economic, environmental, and energy-related aspects of the proposal. Communications should identify both docket numbers and be submitted in triplicate to the address listed above. Commenters wishing the FAA to acknowledge receipt of their comments on this notice must submit with those comments a self-addressed, stamped postcard on which the following statement is made: ''Comments to Docket No. FAA–2013–0596/Airspace Docket No. 13–ACE–11.'' The postcard will be date/time stamped and returned to the commenter.

Availability of NPRMs

An electronic copy of this document may be downloaded through the Internet at *http://www.regulations.gov.* Recently published rulemaking documents can also be accessed through the FAA's Web page at *http://www.faa.gov/airports_airtraffic/air_traffic/publications/airspace_amendments/.*

You may review the public docket containing the proposal, any comments received and any final disposition in person in the Dockets Office (see **ADDRESSES** section for address and phone number) between 9:00 a.m. and 5:00 p.m., Monday through Friday, except Federal holidays. An informal docket may also be examined during normal business hours at the office of the Central Service Center, 2601 Meacham Blvd., Fort Worth, TX 76137.

Persons interested in being placed on a mailing list for future NPRMs should contact the FAA's Office of Rulemaking (202) 267–9677, to request a copy of Advisory Circular No. 11–2A, Notice of Proposed Rulemaking Distribution System, which describes the application procedure.

The Proposal

This action proposes to amend Title 14, Code of Federal Regulations (14 CFR), Part 71 by modifying Class E airspace extending upward from 700 feet above the surface at Brewster Field Airport, Holdrege, NE., for standard instrument approach procedures at the airport. Airspace reconfiguration is necessary due to the decommissioning of the Holdrege NDB and the cancellation of the NDB approach, thereby removing the 7-mile segment extending from the 6.6-mile radius of the airport. Controlled airspace is necessary for the safety and management of IFR operations at the airport. Geographic coordinates would also be adjusted to coincide with the FAA's aeronautical database.

Class E airspace areas are published in Paragraph 6005 of FAA Order 7400.9X, dated August 7, 2013 and effective September 15, 2013, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designation listed in this document would be published subsequently in the Order.

The FAA has determined that this proposed regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore, (1) is not a ''significant

regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the U.S. Code. Subtitle 1, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority. This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it would amend controlled airspace at Brewster Field Airport, Holdrege, NE.

Environmental Review

This proposal will be subject to an environmental analysis in accordance with FAA Order 1050.1E, ''Environmental Impacts: Policies and Procedures'' prior to any FAA final regulatory action.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

The Proposed Amendment

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

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

The authority citation for part 71 continues to read as follows:

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

§ 71.1 [Amended]

The incorporation by reference in 14 CFR 71.1 of FAA Order 7400.9X, Airspace Designations and Reporting Points, dated August 7, 2013, and effective September 15, 2013, is amended as follows:

Paragraph 6005 Class E Airspace areas extending upward from 700 feet or more above the surface of the earth.

* * * * *

ACE NE E5 Holdrege, NE [Amended]

Holdrege, Brewster Field Airport, NE
(Lat. 40°27′08″ N., long. 99°20′11″ W.)

Kearney VOR
(Lat. 40°43′32″ N., long. 99°00′19″ W.)

That airspace extending upward from 700 feet above the surface within a 6.6-mile radius of Brewster Field Airport, and within 2.6 miles each side of the Kearney VOR 222° radial extending from the 6.6-mile radius to 11 miles northeast of the airport.

Issued in Fort Worth, TX, on December 18, 2013.

David P. Medina,

Manager, Operations Support Group, ATO Central Service Center.

[FR Doc. 2014–00114 Filed 1–7–14; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 71

[Docket No. FAA–2013–0606; Airspace Docket No. 13–ACE–12]

Proposed Establishment of Class E Airspace; Warsaw, MO

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This action proposes to establish Class E airspace at Warsaw, MO. Controlled airspace is necessary to accommodate new Standard Instrument Approach Procedures (SIAP) at Warsaw Municipal Airport. The FAA is taking this action to enhance the safety and management of Instrument Flight Rules (IFR) operations for SIAPs at the airport.

DATES: Comments must be received on or before February 24, 2014.

ADDRESSES: Send comments on this proposal to the U.S. Department of Transportation, Docket Operations, 1200 New Jersey Avenue SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–0001. You must identify the docket number FAA–2013–0606/Airspace Docket No. 13–ACE–12, at the beginning of your comments. You may also submit comments through the Internet at *http://www.regulations.gov.* You may review the public docket containing the proposal, any comments received, and any final disposition in person in the Dockets Office between 9:00 a.m. and 5:00 p.m., Monday through Friday, except Federal holidays. The Docket Office (telephone 1–800–647–5527), is on the ground floor of the building at the above address.

FOR FURTHER INFORMATION CONTACT: Scott Enander, Central Service Center, Operations Support Group, Federal Aviation Administration, Southwest Region, 2601 Meacham Blvd., Fort Worth, TX 76137; telephone: (817) 321–7716.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested parties are invited to participate in this proposed rulemaking by submitting such written data, views, or arguments, as they may desire. Comments that provide the factual basis supporting the views and suggestions presented are particularly helpful in developing reasoned regulatory decisions on the proposal. Comments are specifically invited on the overall regulatory, aeronautical, economic, environmental, and energy-related aspects of the proposal. Communications should identify both docket numbers and be submitted in triplicate to the address listed above. Commenters wishing the FAA to acknowledge receipt of their comments on this notice must submit with those comments a self-addressed, stamped postcard on which the following statement is made: ''Comments to Docket No. FAA–2013–0606/Airspace Docket No. 13–ACE–12.'' The postcard will be date/time stamped and returned to the commenter.

Availability of NPRMs

An electronic copy of this document may be downloaded through the Internet at *http://www.regulations.gov.* Recently published rulemaking documents can also be accessed through the FAA's Web page at *http://www.faa.gov/airports_airtraffic/air_traffic/publications/airspace_amendments/.*

You may review the public docket containing the proposal, any comments received and any final disposition in person in the Dockets Office (see **ADDRESSES** section for address and phone number) between 9:00 a.m. and 5:00 p.m., Monday through Friday, except Federal holidays. An informal docket may also be examined during normal business hours at the office of the Central Service Center, 2601 Meacham Blvd., Fort Worth, TX 76137.

Persons interested in being placed on a mailing list for future NPRMs should contact the FAA's Office of Rulemaking

(202) 267–9677, to request a copy of Advisory Circular No. 11–2A, Notice of Proposed Rulemaking Distribution System, which describes the application procedure.

The Proposal

This action proposes to amend Title 14, Code of Federal Regulations (14 CFR), Part 71 by establishing Class E airspace extending upward from 700 feet above the surface within a 6.3-mile radius to accommodate new standard instrument approach procedures at Warsaw Municipal Airport, Warsaw, MO. Controlled airspace is needed for the safety and management of IFR operations at the airport.

Class E airspace areas are published in Paragraph 6005 of FAA Order 7400.9X, dated August 7, 2013 and effective September 15, 2013, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designation listed in this document would be published subsequently in the Order.

The FAA has determined that this proposed regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore, (1) is not a ''significant regulatory action'' under Executive Order 12866; (2) is not a ''significant rule'' under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

The FAA's authority to issue rules regarding aviation safety is found in Title 49 of the U.S. Code. Subtitle 1, Section 106 describes the authority of the FAA Administrator. Subtitle VII, Aviation Programs, describes in more detail the scope of the agency's authority. This rulemaking is promulgated under the authority described in Subtitle VII, Part A, Subpart I, Section 40103. Under that section, the FAA is charged with prescribing regulations to assign the use of airspace necessary to ensure the safety of aircraft and the efficient use of airspace. This regulation is within the scope of that authority as it would establish controlled airspace at Warsaw Municipal Airport, Warsaw, MO.

Environmental Review

This proposal will be subject to an environmental analysis in accordance with FAA Order 1050.1E, ''Environmental Impacts: Policies and Procedures'' prior to any FAA final regulatory action.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

The Proposed Amendment

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

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

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

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

§ 71.1 [Amended]

■ 2. The incorporation by reference in 14 CFR 71.1 of FAA Order 7400.9X, Airspace Designations and Reporting Points, dated August 7, 2013, and effective September 15, 2013, is amended as follows:

Paragraph 6005 Class E Airspace areas extending upward from 700 feet or more above the surface of the earth.

* * * * *

ACE MO E5 Warsaw, MO [New]

Warsaw Municipal Airport, MO
(Lat. 38°20′52″ N., long. 93°20′43″ W.)

That airspace extending upward from 700 feet above the surface within a 6.3-mile radius of Warsaw Municipal Airport

Issued in Fort Worth, TX, on December 18, 2013.

David P. Medina,

Manager, Operations Support Group, ATO Central Service Center.

[FR Doc. 2014–00113 Filed 1–7–14; 8:45 am]

BILLING CODE 4910–13–P

COMMODITY FUTURES TRADING COMMISSION

17 CFR Chapter I

Request for Comment on Application of Commission Regulations to Swaps Between Non-U.S. Swap Dealers and Non-U.S. Counterparties Involving Personnel or Agents of the Non-U.S. Swap Dealers Located in the United States

AGENCY: Commodity Futures Trading Commission.

ACTION: Request for comment.

SUMMARY: The Commodity Futures Trading Commission (''Commission'') is requesting comment on an advisory issued by Commission staff on November 14, 2013 (the ''Staff Advisory''), regarding the applicability of certain Commission regulations to the activity in the United States of swap dealers (''SDs'') and major swap participants (''MSPs'') registered with the Commission that are established in jurisdictions other than the United States (whether an affiliate or not of a U.S. person, a ''non-U.S. SD'' or ''non-U.S. MSP'').

DATES: Comments must be received on or before March 10, 2014.

ADDRESSES: You may submit comments by any of the following methods:

- The agency's Web site, at *http://comments.cftc.gov.* Follow the instructions for submitting comments through the Web site.
- *Mail:* Melissa D. Jurgens, Secretary of the Commission, Commodity Futures Trading Commission, Three Lafayette Centre, 1155 21st Street NW., Washington, DC 20581.
- *Hand Delivery/Courier:* Same as mail above.
- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.

Please submit your comments using only one method.

All comments must be submitted in English, or if not, accompanied by an English translation. Comments may be posted as received to *http://www.cftc.gov.* You should submit only information that you wish to make available publicly. If you wish the Commission to consider information that may be exempt from disclosure under the Freedom of Information Act, a petition for confidential treatment of the exempt information may be submitted according to the established procedures in CFTC Regulation 145.9 (17 CFR 145.9).

The Commission reserves the right, but shall have no obligation, to review,

pre-screen, filter, redact, refuse, or remove any or all of your submission from *www.cftc.gov* that it may deem to be inappropriate for publication, such as obscene language. All submissions that have been redacted or removed that contain comments on the merits of the rulemaking will be retained in the public comment file and will be considered as required under the Administrative Procedure Act and other applicable laws, and may be accessible under the Freedom of Information Act.

FOR FURTHER INFORMATION CONTACT: Gary Barnett, Director, 202–418–5977, *gbarnett@cftc.gov*, or Frank Fisanich, Chief Counsel, 202–418–5949, *ffisanich@cftc.gov*, Division of Swap Dealer and Intermediary Oversight, Commodity Futures Trading Commission, Three Lafayette Centre, 1155 21st Street NW., Washington, DC 20581.

SUPPLEMENTARY INFORMATION:

I. Background

On July 21, 2010, President Obama signed the Dodd-Frank Wall Street Reform and Consumer Protection Act [1] (''Dodd-Frank Act'' or ''Dodd-Frank''), which, in Title VII, established a new regulatory framework for swaps.

In the three years since the enactment of Dodd-Frank, the Commission has finalized 68 rules, orders, and guidance statements in the process of implementing Title VII of the Dodd-Frank Act. The finalized rules promulgated under section 4s of the CEA, added by the Dodd-Frank Act, address registration of SDs and MSPs and other substantive requirements applicable to SDs and MSPs, while guidance published by the Commission provided the Commission's general views regarding the scope of the cross-border application of such rules.[2] Among other things, the Guidance sets forth the Commission's general views on how it ordinarily expects to apply, in accordance with section 2(i) of the CEA, the CEA and certain Commission regulations applicable on a transaction-by-transaction basis (the ''transactional requirements'') to swaps between a non-U.S. SD and a non-U.S. person, including swaps involving guaranteed or conduit affiliates of U.S. persons.[3] In addition, the Guidance addressed the circumstances under which the transactional requirements could be satisfied through substituted compliance.[4]

With few exceptions, the delayed compliance dates for the Commission's regulations implementing requirements of section 4s of the CEA have passed and SDs and MSPs are now required to be in full compliance with such regulations upon registration with the Commission.[5]

Subsequent to publication of the Guidance, swap market participants have raised questions with Commission staff regarding compliance by non-U.S. SDs with the transactional requirements when using personnel or agents located in the United States to enter into swaps with non-U.S. persons. In other words, swap market participants have asked whether the transactional requirements would apply to these swaps (and if so, whether substituted compliance may be available for these swaps) even though such swaps are between two non-U.S. persons, regardless of whether the activities of the non-U.S. SD that lead to such swaps take place in the United States.

In response to these inquires, the Staff Advisory [6] was issued, stating that for swaps between a non-U.S. SD and a non-U.S. person, the transactional requirements either do not apply or, in some cases, may be subject to substituted compliance if the activities of the non-U.S. SD take place outside the United States. The Staff Advisory further stated that, for transactions arranged, executed, or negotiated by personnel or agents located in the United States of non-U.S. SDs (whether affiliates or not of a U.S. person) regularly using personnel or agents located in the U.S. to arrange, negotiate, or execute swaps with non-U.S. persons (the ''Covered Transactions''), the non-U.S. SD generally would be required to comply with the transactional requirements. The Staff Advisory further stated that this view would also apply to a Covered Transaction booked in a non-U.S. branch of the non-U.S. SD.[7]

The Commission notes that subsequent to the Staff Advisory, the Commission's Divisions of Swap Dealer and Intermediary Oversight, Market Oversight, and Clearing and Risk provided non-U.S. SDs time-limited staff no-action relief from certain transactional requirements for Covered Transactions,[8] and have recently extended such relief until September 15, 2014, subject to certain terms and conditions stated in such Divisions' no-action letter.[9]

II. Request for Comment

In view of the complex legal and policy issues involved with respect to the Staff Advisory, the Commission is soliciting comment from all interested parties to further inform the Commission's and its staff's deliberations regarding the subjects addressed in the Staff Advisory.

Accordingly, the Commission requests comment on all aspects of the Staff Advisory, including but not limited to the following points. If a comment relates to one of the specific points noted below, please identify the point by number and provide a detailed rationale supporting the response.

1. The Commission invites comment on whether the Commission should adopt the Staff Advisory as Commission policy, in whole or in part.

2. The Commission invites commenters to provide their views on whether transactional requirements should apply to Covered Transactions with non-U.S. persons who are not guaranteed or conduit affiliates of U.S. persons. Please provide a detailed analysis of any such view and its effect on other aspects of the Commission's cross-border policy, if any.

3. The Commission invites comment on whether there should be any differentiation in treatment of swaps with non-U.S. counterparties depending on the nature of the SD (i.e., whether it is a guaranteed affiliate or a conduit affiliate of a U.S. person).

[1] Public Law 111–203, 124 Stat. 1376 (2010).

[2] *See* Interpretive Guidance and Policy Statement Regarding Compliance with Certain Swap Regulations 78 FR 45292 (July 26, 2013) (hereinafter, the ''Guidance'').

[3] For purposes of this notice, the Commission would generally interpret the terms ''U.S. person,'' ''guaranteed affiliate,'' and ''affiliate conduit'' in the same way as described in the Guidance, 78 FR at 45316–45317, 45350–45359. The Commission uses the term ''non-U.S. person'' to refer to any person outside its interpretation of the term ''U.S. person.''

[4] The Guidance generally describes the policy and procedural framework under which the Commission would consider a substituted compliance program with respect to Commission regulations applicable to non-U.S. SDs. Specifically, the Commission described circumstances where it expected that compliance with a comparable regulatory requirement of a foreign jurisdiction would serve as a reasonable substitute for compliance with the attendant requirements of the CEA and the Commission's regulations, 78 FR at 45342–45344.

[5] The compliance dates are summarized on the Compliance Dates page of the Commission's Web site. (*http://www.cftc.gov/LawRegulation/DoddFrankAct/ComplianceDates/index.htm.*)

[6] Division of Swap Dealer and Intermediary Oversight, Applicability of Transaction-Level Requirements to Activity in the United States, Nov. 14, 2013. Available at: *http://www.cftc.gov/ucm/groups/public/@1rlettergeneral/documents/letter/13-69.pdf.* As stated in the Staff Advisory, the advisory, and the views expressed therein, represent the views of the Division of Swap Dealer and Intermediary Oversight only, and do not represent the position or view of the Commission or of any other office or division of the Commission.

[7] *See* the Staff Advisory, *supra* note 6.

[8] *See* CFTC Staff Letter 13–71, available on the Commission's Web site: *http://www.cftc.gov/ucm/groups/public/@lrlettergeneral/documents/letter/13-71.pdf.*

[9] *See* CFTC Staff Letter 14–01, available on the Commission's Web site.

4. To the extent a non-U.S. SD must comply with the transactional requirements when entering a Covered Transaction, should the non-U.S. SD be able to rely on a substituted compliance program for purposes of complying with the relevant transactional requirements? If so, should substituted compliance be available for all transactional requirements or only specific requirements? Which requirements? Would the response be different depending on the nature of the counterparty (i.e., whether the non-U.S. counterparty is a guaranteed affiliate or a conduit affiliate of a U.S. person)?

5. The Commission invites comment on the meaning of ''regularly'' in the phrase ''persons regularly arranging, negotiating, or executing swaps for or on behalf of an SD'' and whether such persons are performing core, front-office activities of that SD's swap dealing business. If not, what specific activities would constitute the core, front-office activities of an SD's swap dealing business? What characteristics or factors distinguish a ''core, front-office'' activity from other activities? Please be exhaustive in describing such activities.

6. The Commission invites comment on the scope and degree of ''arranging, negotiating, or executing'' swaps as used in this context.

Issued in Washington, DC, on January 3, 2014, by the Commission.

Melissa D. Jurgens,

Secretary of the Commission.

Appendices To Request for Comment on Application of Commission Regulations to Swaps Between Non-U.S. Swap Dealers and Non-U.S. Counterparties Involving Personnel or Agents of the Non-U.S. Swap Dealers Located in the United States

Appendix 1—Commission Voting Summary

On this matter, Chairman Gensler and Commissioners Chilton and Wetjen voted in the affirmative. Commissioner O'Malia voted in the negative.

Appendix 2—Dissenting Statement of Commissioner Scott D. O'Malia

If you thought that the Commission's approach last year regarding cross-border issues resulted in an unsound rulemaking process, the start of 2014 is no better.

Today's announcement of the request for comment on a staff Advisory abrogates the Commission's fundamental legal obligations under the Administrative Procedure Act (''APA'') and provides another example of the Commission's unsound rule implementation process.

Making matters worse, today's request for comment is completely outside the scope of the cross-border Guidance and the Exemptive Order as the Commission did not address the issue relating to swaps negotiated between non-U.S. swap dealers (''SDs'') and non-U.S. counterparties acting through agents of the non-U.S. SDs located in the United States. This is simply a strategic move by the Commission to try to duck blame for consistently circumventing the fundamental tenets of the APA and failing to adhere faithfully to the express congressional directive to limit the extraterritorial application of the Dodd-Frank Act to foreign transactions that ''have a direct and significant connection with activities in, or effect on, commerce of the United States.'' [1]

Moreover, I question why the Commission has decided to request comment on a narrow issue of the extraterritorial application of Dodd-Frank, while essentially ignoring the dozens of comments already filed as part of the Commission's cross-border Exemptive Order.[2] Simply requesting comment on a staff Advisory does not endorse the validity of the cross-border Guidance or the staff Advisory issued based on the Guidance.

Additionally, I have serious concerns with the evolving jurisdictional application of the Commission's authority over cross-border trades. It appears based on the staff Advisory, that the Commission is applying a ''territorial'' jurisdiction test to elements of a trade between non-U.S. entities. To better understand the legal underpinnings of this position, I have included several additional questions to be considered as part of the overall comment file. It is my hope that public comments will provide greater clarity regarding our cross-border authority and identify areas where we must harmonize global rules with our international regulatory partners in the near future. It makes no sense to apply guidance or staff advisories that do not enjoy the full support and authority provided through rulemakings based on the Commodity Exchange Act (''CEA'').

Looking forward into this year, the CFTC needs to do away with the reflexive rule implementation process via staff no-action and advisories that are not voted on by the Commission. It should be the goal of the Commission to develop rules that adhere to the APA and ensure proper regulatory oversight, transparency and promote competition in the derivatives space.

In this regard, I would like to seek additional comment on the following points:

1. Please provide your views on whether Covered Transactions with non-U.S. persons who are not guaranteed or conduit affiliates of U.S. persons meet the direct and significant test under CEA section 2(i).[3] Please provide a detailed analysis of any such view and its effect on other aspects of the Commission's cross-border policy, if any. Would your view change depending on whether a non-U.S. SD is a guaranteed affiliate or a conduit affiliate of a U.S. person?

2. CEA section 2(a)(1) [4] provides for the general jurisidiction of the Commission. Please provide your views on whether Covered Transactions with non-U.S. persons who are not guaranteed or conduit affiliates of U.S. persons fall within the Commission's jurisdiction under CEA section 2(a)(1) or any other provision of the CEA providing for Commission jurisdiction. Please provide a detailed analysis of any such view and its effect on other aspects of the Commission's cross-border policy, if any. Would your view change depending on the nature of the non-U.S. SD (i.e., whether it is a guaranteed affiliate or a conduit affiliate of a U.S. person)?

3. To the extent that Covered Transactions fall within the Commission's jurisdiction, should a non-U.S. SD be required to comply with all, or only certain, Transaction-Level Requirements? Please provide a detailed analysis of any such view and its effect on other aspects of the Commission's cross-border policy, if any. Would your view change depending on the nature of the non-U.S. SD (i.e., whether it is a guaranteed affiliate or a conduit affiliate of a U.S. person)?

4. In the open meeting to consider the cross-border final guidance and cross-border phase-in exemptive order, I asked about the Commission's enforcement and legal authority under the cross-border guidance. The Commission's General Counsel replied, ''[T]he guidance itself is not binding strictly. We couldn't go into court and, in a count of the complaint, list a violation of the guidance as an actionable claim.'' [5] If the Commission adopts the staff Advisory as Commission policy (and not through the rulemaking process), please provide your views on the Commission's ability to enforce such policy.

[1] 7 U.S.C. 2(i).

[2] *See* Statement of Dissent by Commissioner Scott D. O'Malia, Interpretive Guidance and Policy Statement Regarding Compliance With Certain Swap Regulations and Related Exemptive Order, July 12, 2013, *http://www.cftc.gov/PressRoom/SpeechesTestimony/omaliastatement071213b.*

[3] 7 U.S.C. 2(i).

[4] 7 U.S.C. 2(a)(1).

[5] Transcript of Open Meeting to Consider Cross-Border Final Guidance and Cross-Border Phase-In Exemptive Order (July 12, 2013), page 79.

[FR Doc. 2014–00080 Filed 1–7–14; 8:45 am]

BILLING CODE 6351–01–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2010–0335; FRL–9905–04–Region 6]

Approval and Promulgation of Implementation Plans; Texas; Procedures for Stringency Determinations and Minor Permit Revisions for Federal Operating Permits

AGENCY: Environmental Protection Agency (EPA).

ACTION: Withdrawal of proposed rule.

SUMMARY: On September 10, 2013, the Environmental Protection Agency (EPA)

published a direct final rule approving portions of three revisions to the Texas State Implementation Plan (SIP) concerning the Texas Federal Operating Permits Program. EPA received timely, adverse comments on the direct final rule and withdrew the direct final rule on November 6, 2013. In our withdrawal of the direct final rule, we indicated we would address the comments received through the proposed rule published on September 10, 2013. Subsequent to our withdrawal of the direct final, EPA received a letter dated December 19, 2013, from the Texas Commission on Environmental Quality stating that the December 17, 1999; October 4, 2001; and August 11, 2003 revisions specific to stringency determinations and minor permit revisions for Federal Operating Permits have been withdrawn from our consideration as revisions to the Texas SIP. Accordingly, EPA is withdrawing the proposed approval and finds that no further action is necessary on the portions of the three SIP revisions specific to stringency determinations and minor permit revisions for the Texas Federal Operating Permits Program. The State's action also withdraws from EPA's review the Federal Operating Permits Program component of the January 22, 2010 Consent Decree between EPA and the BCCA Appeal Group, Texas Association of Business, and Texas Oil and Gas Association. This withdrawal is being taken under section 110 and parts C and D of the Federal Clean Air Act.

DATES: The proposed rule published on September 10, 2013 (78 FR 55234), is withdrawn as of January 8, 2014.

FOR FURTHER INFORMATION CONTACT: Ms. Adina Wiley (6PD–R), Air Permits Section, Environmental Protection Agency, Region 6, 1445 Ross Avenue (6PD–R), Suite 1200, Dallas, TX 75202–2733. The telephone number is (214) 665–2115. Ms. Wiley can also be reached via electronic mail at *wiley.adina@epa.gov.*

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: December 20, 2013.

Samuel Coleman,

Acting Regional Administrator, Region 6.

[FR Doc. 2013–31569 Filed 1–7–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R07–OAR–2013–0674; FRL–9905–02–Region 7]

Approval and Promulgation of Implementation Plans; State of Missouri; Control of Nitrogen Oxide Emissions From Large Stationary Internal Combustion Engines

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to approve a State Implementation Plan (SIP) revision submitted by the State of Missouri to EPA on September 21, 2010, with a supplemental revision submitted on July 3, 2013. The purpose of the SIP revision is to incorporate revisions to a Missouri regulation to control Nitrogen Oxide (NO_X) emissions from large stationary internal combustion engines. This revision includes an emission rate limitation for both large stationary diesel and dual fuel internal combustion engines and adds an exemption for compression ignited stationary internal combustion engines that emit 25 tons or less of NO_X between May 1 and September 30. EPA has determined that the SIP revision submitted by the State of Missouri satisfies the applicable requirements of the Clean Air Act (CAA or Act), and in particular, the April 21, 2004, final Federal Phase II NO_X SIP Call.

DATES: Comments must be received on or before February 7, 2014.

ADDRESSES: Submit your comments identified by Docket ID No. EPA–R07–OAR–2013–0674, by one of the following methods:

1. *http://www.regulations.gov.* Follow the on-line instructions for submitting comments.
2. *Email: kemp.lachala@epa.gov.*
3. *Mail:* Ms. Lachala Kemp, Air Planning and Development Branch, U.S. Environmental Protection Agency, Region 7, Air and Waste Management Division, 11201 Renner Boulevard, Lenexa, Kansas 66219.
4. *Hand Delivery or Courier:* Deliver your comments to Ms. Lachala Kemp, Air Planning and Development Branch, U.S. Environmental Protection Agency, Region 7, Air and Waste Management Division, 11201 Renner Boulevard, Lenexa, KS 66219.

Instructions: Direct your comments to Docket ID No. EPA–R07–OAR–2013–0674. 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 through *http://www.regulations.gov* or email information that you consider to be CBI or otherwise protected. 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 should be free of any defects or viruses.

Docket: All documents in the electronic docket are listed in the *http://www.regulations.gov index.* Although listed in the index, some information is not publicly available, i.e., 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 U.S. Environmental Protection Agency, Region 7, 11201 Renner Boulevard, Lenexa, Kansas 66219 from 8:00 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The interested persons wanting to examine these documents should make an appointment with the office at least 24 hours in advance.

FOR FURTHER INFORMATION CONTACT: Ms. Lachala Kemp, Air Planning and Development Branch U.S. Environmental Protection Agency, Region 7, 11201 Renner Boulevard, Lenexa, KS 66219; *telephone number:* (913) 551–7214; *fax number:* (913) 551–7065; *email address: kemp.lachala@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document, ''we,'' ''us,'' or ''our'' refer to EPA. This section provides additional information by addressing the following questions:

Table of Contents

I. Background for the Proposal
II. Summary of Missouri's SIP Revision
III. EPA's Proposed Action

I. Background for the Proposal

EPA is proposing to approve a State Implementation Plan (SIP) revision submitted by the State of Missouri to EPA on September 21, 2010, with a supplemental revision submitted on July 3, 2013. The purpose of the SIP revision is to incorporate changes to a Missouri regulation (Title 10 of the Code of State Regulations (CSR) 10–6.390) to control Nitrogen Oxide (NO_X) emissions from large stationary internal combustion (IC) engines to ensure compliance with the federal NO_X control plan to reduce the transport of air pollutants.[1] EPA finalized the second phase (Phase II) of its rule known as the NO_X SIP Call Rule on April 21, 2004 (69 FR 21604). Phase II required the eastern one-third of Missouri to participate in the NO_X SIP Call and included a provision related to source categories of IC engines. The IC provision established a requirement to decrease emissions from diesel and dual fuel stationary IC engines by ninety percent. 69 FR 21608. Phase II of the NO_X SIP Call also required each state in the control region to submit a SIP that contained adequate provisions prohibiting its sources from emitting air pollutants that would contribute significantly to nonattainment, or interfere with maintenance, in one or more downwind states. *See, generally,* 69 FR at 21608–38.

Missouri's rule establishes emissions levels for large stationary internal combustion engines of greater than one thousand three hundred horsepower located in the counties of Bollinger, Butler, Cape Girardeau, Carter, Clark, Crawford, Dent, Dunklin, Franklin, Gasconade, Iron, Jefferson, Lewis, Lincoln, Madison, Marion, Mississippi, Montgomery, New Madrid, Oregon, Pemiscot, Perry, Pike, Ralls, Reynolds, Ripley, St. Charles, St. Francois, St. Louis, Ste. Genevieve, Scott, Shannon, Stoddard, Warren, Washington, and Wayne counties, and the City of St. Louis in Missouri. To be subject to this rule, the IC engines must either have emitted greater than one ton per day of NO_X on average during the period from May 1 through September 30 of 1995, 1996 or 1997, or began operations after September 30, 1997. 10 CSR 10–6.390(1)(A), (B).

EPA's analysis of the State's SIP revision is discussed below. As a result of EPA's analysis, we are proposing to approve this request to revise Missouri's SIP and include this 2010 amendment to the Missouri rule.

II. Summary of Missouri's SIP Revision

The Missouri rule establishes emission rate limits using current reporting requirements for both large stationary diesel engines and dual fuel IC engines and adds a twenty five ton NO_X exemption.

Any compression ignited stationary engine that begins operation after September 30, 1997, and emits twenty-five (25) tons or less of NO_X during the period from May 1 through September 30 is also exempt from certain emission rate limits found at 10 CSR 10–6.390(3)(B)3. and 4. This exemption (hereinafter referred to as the ''twenty-five ton NO_X exemption'') is based on the previous year's NO_X emissions during the May 1 through September 30 period. If the exemption limit is exceeded, for any reason, the engine in question will be required to meet the applicable limits of subsection (3)(B) each year thereafter. The exemption does not apply to the record keeping and reporting requirements of 10 CSR 10–6.390(4).

Section 110(l) of the CAA states that EPA shall not approve a revision of a SIP if the revisions would interfere with any applicable requirement concerning attainment and reasonable further progress, or any other applicable requirement of the CAA. The State's SIP revision included a demonstration that this twenty-five ton NO_X exemption for compression ignited stationary IC engines will not adversely impact air quality. The analysis also showed that the exemption will not affect the State's ability to meet its NO_X SIP Call obligations.

In this analysis, the State focuses on the eastern one-third of Missouri, which is defined by the Phase II NO_X SIP Call. This area is also located south and adjacent to the St. Louis nonattainment area for ozone, which is generally in the path of the predominant wind direction on typical high ozone days. The overall analysis on emissions for the specific area demonstrates that the additional impact of these exempt units on St. Louis ozone and NO_X levels is insignificant.

In addition, the State's analysis also demonstrates that for each year since EPA approved its NO_X SIP Call budget on August 15, 2006 (71 FR 46860), overall ozone season NO_X emissions have been below the State's allowable budget. For utilities, NO_X controls—specifically, two selective catalytic reduction units with overfire air, one low-NO_X burner with overfire air, and two overfire air NO_X control units—have been installed since 2005 in the eastern one-third of Missouri to assist the State with meeting the applicable budgets. Similarly, non-utility boiler and cement kiln NO_X emissions have substantially decreased and stayed below the State's allowable budget during this time. Even with the potential amount of additional NO_X emissions caused by the twenty-five ton NO_X exemption in 10 CSR 10–6.390, the total amount of NO_X emissions would still be under the budgeted level. Further details on the State's analysis can be found in the docket for this rulemaking.

In summary, EPA has reviewed the State's analysis and believes that the twenty-five ton NO_X exemption in 10 CSR 10–6.390 will not adversely impact air quality and will not affect the State's ability to meet its NO_X SIP Call budget obligations.

III. EPA's Proposed Action

In today's rulemaking, EPA is proposing to approve a revision to the Missouri SIP to control NO_X emissions from large stationary internal combustion engines. The revisions will also add a NO_X exemption for compression ignited stationary internal combustion engines that emit 25 tons or less of NO_X during the ozone season. If this level is exceeded, the regular emission rate limits in the regulation would apply. The requirements prescribed in the proposed SIP revision are consistent with the April 21, 2004, final Federal Phase II NO_X SIP Call. EPA has determined that the SIP submitted by the State of Missouri satisfies the applicable requirements of the CAA.

Statutory and Executive Order Reviews

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

[1] The effective date of the rule in Missouri was May 30, 2010.

• Is not a ''significant regulatory action'' subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);

• Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);

• Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);

• Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);

• Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);

• Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);

• Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);

• Is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and

• Does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

In addition, this rule does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), because the SIP is not approved to apply in Indian country located in the state, and EPA notes that it will not impose substantial direct costs on tribal governments or preempt tribal law.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Reporting and recordkeeping requirements.

Dated: December 12, 2013.

Karl Brooks,

Regional Administrator, Region 7.

[FR Doc. 2013–31567 Filed 1–7–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2011–0660; FRL–9901–51–OAR]

RIN 2060–AQ91

Withdrawal of Proposed Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Withdrawal of proposed rule.

SUMMARY: The United States EPA (EPA) is withdrawing the proposal for new source performance standards for emissions of carbon dioxide (CO_2), which was published on April 13, 2012, for new affected fossil fuel-fired electric utility generating units (EGUs). The EPA received more than 2.5 million comments on that notice and has received new information, which together necessitates substantial changes in the proposed requirements. The changes not only affect determinations of potentially covered sources but could also result in substantial changes in what some sources must do to comply with the standards and could thereby cause them to alter planned facility designs or technological control systems. These changes concern the addition of a determination of the best system of emission reduction for fossil fuel-fired boilers and IGCC units; an alternative compliance option for solid fuel-fired EGUs; the treatment of certain units that had received permits to construct but for which construction had not yet commenced; the limits for natural gas-fired stationary combustion turbines; and the application of CO_2 emission fees under the title V operating permit program. These changes are of substantial consequence and are sufficient to merit withdrawal (i.e., rescission) of that notice of proposed rulemaking. At the same time, in a separate notice of proposed rulemaking published in today's **Federal Register**, the EPA is issuing new proposed requirements for new fossil-fuel-fired electric generating units, which are based on different analyses from the original proposal and would establish requirements that differ significantly from the original proposal.

DATES: The proposed rule published on April 13, 2012 (78 FR 22392), is withdrawn as of January 8, 2014.

ADDRESSES: *Docket:* A rulemaking docket for the April 13, 2012, notice of proposed rulemaking was established and identified as EPA–HQ–OAR–2011–0660. 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, EPA 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 legal 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 action will also be available on the Worldwide Web (WWW) through the Technology Transfer Network (TTN). Following signature, a copy of the action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/.* The TTN provides information and technology exchange in various areas of air pollution control.

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:

I. General Information

A. Overview

In 2009, the EPA issued a finding that greenhouse gas (GHG) air pollution may reasonably be anticipated to endanger Americans' public health and welfare, now and in the future, by contributing to climate change. In the notice of proposed rulemaking that was published on April 13, 2012 (April 2012 document), the EPA proposed to limit

GHG emissions from new fossil fuel-fired power plants through standards for CO_2 emissions.[1] These power plants are the largest stationary sources of U.S. GHG emissions.

The April 2012 document proposed federal standards of performance for new fossil fuel-fired power plants that the EPA concluded could be met with existing technology. Specifically, the EPA proposed a single electricity-output-based emission standard of 1,000 pounds of CO_2 per megawatt-hour of gross electrical output (1,000 lb CO_2/MWh) for all new affected fossil fuel-fired power plants. This standard was based on the demonstrated performance of recently constructed, modern natural gas combined cycle (NGCC) units, which the EPA concluded were in wide use throughout the country and were likely to be the predominant fossil fuel-fired technology for new generation in the future. Indeed, modeling conducted in support of that proposal predicted no new coal-fired EGUs would be constructed at least until after 2020. However, the EPA recognized that a very small number of new fossil fuel-fired utility boilers and IGCC units may be built, and if so, they could meet the proposed standard through the use of available carbon capture and storage (CCS) technology. To assist such sources in complying with the standard, the EPA proposed an alternative 30-year averaging option that would be available only for affected coal- and petroleum coke-fired sources complying with the standard through the use of CCS.

In addition, the EPA identified as ''transitional'' sources certain coal-fired power plants that had received approval of their PSD preconstruction permits as of the date of the April 2012 proposal (or that had approved PSD permits that expired and were in the process of being extended, if they were participating in a Department of Energy CCS funding program), and that commenced construction within one year of the date of the April proposal. For those sources, the EPA did not propose a standard of performance.

The EPA also stated that it was not proposing standards of performance for simple cycle combustion turbines or for non-continental sources (i.e., those in Hawaii or the U.S. territories).

In a separate notice of proposed rulemaking published in today's **Federal Register**, the EPA has made several key changes to its original proposal. First, instead of proposing a single limit covering all affected fossil fuel-fired EGUs, the EPA is proposing three different limits: (1) A limit of 1,000 lb CO_2/MWh for large natural gas-fired stationary combustion turbines, (2) a limit of 1,100 lb CO_2/MWh for small natural gas-fired stationary combustion turbines, and (3) a limit of 1,100 lb CO_2/MWh for fossil fuel-fired utility boilers and IGCC units. Second, instead of proposing an alternative 30-year averaging compliance option for new solid fuel-fired EGUs, the EPA is proposing an alternative 7-year (84-operating month) averaging option and is soliciting comment on a limit of 1,000 to 1,050 lb CO_2/MWh. Third, the EPA is no longer excluding all previously identified transitional sources (but is considering a subcategory for one to three coal-fired projects that are still currently under development). Fourth, instead of proposing to exempt simple cycle combustion turbines, the EPA is proposing to exempt units that sell to the grid a relatively small portion of their potential electric output. These exempt units generate less than one-third of their potential electric output over a three year rolling averaging period.

B. Why is the EPA withdrawing the proposed rule?

In response to the proposed rule, the EPA received over 2.5 million public comments on all aspects of its proposal. Many commenters were supportive of the Agency's proposed actions, other commenters opposed the proposed actions, and many commenters provided new information and/or recommended significant changes in the EPA's proposed requirements. In addition, the EPA has obtained and analyzed new information that significantly alters its views on important assumptions and which counsel for major changes in some of the requirements proposed in the April 2012 document.

We fully describe the actions we are proposing to take in response to the comments received and the results of our analyses of new information in a notice of proposed rulemaking published elsewhere in today's **Federal Register**. The following is a description of the principal reasons why those changes warrant rescission of the April 2012 document and issuance of a new proposal.

1. Changes in Proposed Applicability Requirements

Changes to the proposed rule's applicability will impact which sources are potentially covered. By changing the proposed rule's applicability, projects based on NGCC technology that are intended to, and that do, generate less than one-third of their potential electric output on a three year rolling average, which would have been covered by the original proposal, are not covered by today's proposal. Such projects could be beneficial because they are likely to be more efficient and lower emitting and could potentially cost less than natural gas-fired simple cycle combustion turbines in some instances. If we did not withdraw the original proposal, developers might not consider this technology because they may perceive a greater risk that we would finalize the applicability requirements of the original proposal. This could have the unintended effect of potentially stifling development of NGCC technology that can be used to meet peak energy demand.

2. Changes With Respect to Proposed Standards

The Agency is also proposing significant substantive changes from the original proposal in today's new proposal with respect to the standards themselves.

a. Projected New Coal-Fired Electrical Generating Capacity

In the April 2012 proposal, although the EPA acknowledged the possibility of a very small amount of construction of new coal-fired generating capacity, the EPA relied primarily on several modeling analyses, including analyses using the EPA's Integrated Planning Model (IPM), which projected that there would be no construction of new coal-fired generation through the year 2030 without CCS even assuming the potential for higher future electric demand or with higher future natural gas prices. Comments received, along with new information, have brought more clearly into focus the possibility that, in fact, there could well be limited new coal-fired generating capacity being constructed within the planning timeframe covered by the proposed rule. This new capacity could be in response to the need for companies to establish or maintain fuel diversity in their generation portfolios or the ability of some companies to combine coal-fired generation of electricity with the profitable sale of by-products from gasification or combustion of coal. As a result, even though our baseline analysis does not project any new coal that would not meet the originally proposed standard, the EPA believes it is appropriate to develop separate standards for coal-fired capacity, which, as it turns out, differ from those for new natural gas-fired EGUs.

[1] In the April 2012 document, we referred to these sources, interchangeably, as power plants, affected sources, fossil fuel-fired electric generating units, and electric generating units (EGUs).

b. Best System of Emission Reduction for Coal-Fired EGUs

The April 2012 proposal set a single standard of performance for all affected fossil fuel-fired EGUs, regardless of generation technology or fuel, based on our proposed findings that the best system of emission reduction adequately demonstrated (BSER) for fossil fuel-fired units is natural gas combined cycle technology. Thus, in the April 2012 proposal, we did not propose a separate BSER for coal- and other solid fossil fuel-fired EGUs, although we identified carbon capture and storage (or sequestration) (CCS) technology as a compliance alternative for those EGUs and we proposed a 30-year averaging compliance option for those EGUs that implemented CCS.

We received significant public comments on this approach. Our evaluation of those comments has led us to modify significantly our conclusions regarding the BSER and the resulting emission limitations for fossil fuel-fired sources, and we no longer consider it appropriate to propose a single standard for all such units.

Instead, we are proposing separate emission standards based on separate BSER determinations for (i) fossil fuel-fired utility boilers and IGCC units and (ii) natural gas-fired stationary combustion turbines. For fossil fuel-fired utility boilers and IGCC units, we are proposing partial-capture CCS as the BSER. Additionally, we now believe that a shorter compliance averaging option than the 30-year scheme proposed in the April 2012 notice may be more appropriate.

These changes are significant. Moreover, they affect at least one unit in advanced stages of project development. As a result, the EPA believes it is important to withdraw the original document, in part to make it clear to the developer of this project—and any other projects in development—that their new source performance standards will be based on a BSER determination that is more closely aligned with technology appropriate to those projects.

c. Emission Standards for Natural-Gas Fired Stationary Combustion Units

As noted, in the new action, the EPA is proposing separate emission standards for fossil fuel-fired utility boilers and IGCC units and for natural gas-fired stationary combustion turbines. In the new proposal, the EPA also is proposing separate emission standards for smaller natural gas-fired stationary combustion turbines and for larger natural gas-fired stationary combustion turbines. This differentiation may be significant to projects under development.

d. Treatment of Transitional Sources

We received numerous comments objecting to our proposed treatment of transitional sources. In light of many of those comments and additional information we have obtained, we have reassessed this issue and are revisiting our proposed treatment of these types of units.

e. Title V Permit Fees

When EPA finalizes CO_2 emission requirements for new fossil fuel-fired EGUs, GHGs will, for the first time, fall within the definition of ''regulated air pollutant'' in parts 70 and 71, which implement the title V permitting program. This would trigger requirements related to the calculation of permit fees under federal and state title V operating permit programs. The April 2012 proposal did not address title V fee issues related to GHG emissions, but we recognize that it is important to do so. The reproposal addresses title V fees for GHG emissions and includes several options for calculating the reasonable costs associated with GHG permitting.

II. Impacts of This withdrawal

The April 2012 document provided estimated air and energy impacts, as well as projected compliance costs, economic and employment impacts, and benefits associated with the proposed rule. This action withdraws the April 2012 proposal, and thus any projected impacts associated with it are being replaced with the results of a new assessment accompanying the notice of proposed rulemaking published elsewhere in today's **Federal Register**.

III. Statutory Authority

Pursuant to CAA section 307(d)(1)(V), the Administrator is determining that this action is subject to the provisions of CAA section 307(d). The statutory authority for this action is provided by sections 111, 301 and 307(d) of the CAA as amended (42 U.S.C. 7411, 7601 and 7607(d)).

List of Subjects in 40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control.

Dated: September 20, 2013.

Gina McCarthy,

Administrator.

[FR Doc. 2013–31079 Filed 1–7–14; 12:45 pm]

BILLING CODE 6560–50–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Parts 300 and 665

[Docket No. 130708597–3999–01]

RIN 0648–BD46

Western Pacific Pelagic Fisheries; U.S. Territorial Catch and Fishing Effort Limits

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

ACTION: Proposed rule; proposed specifications; request for comments.

SUMMARY: NMFS seeks public comment on two proposed actions. First, NMFS proposes to establish a management framework for specifying catch and fishing effort limits and accountability measures for pelagic fisheries in the U.S. Pacific territories (American Samoa, Guam, and the Northern Mariana Islands). The framework would authorize the government of each territory to allocate a portion of its catch or fishing effort limit to a U.S. fishing vessel or vessels through a specified fishing agreement, and establish the criteria that an agreement would need to satisfy. The proposed framework also includes accountability measures for adhering to catch and fishing effort limits to ensure sustainability.

Second, NMFS proposes an annual limit of 2,000 metric tons (mt) of longline-caught bigeye tuna for each territory, using the framework described in the proposed rule. NMFS would allow a territory to allocate up to 1,000 mt of the 2,000 mt each year to a U.S. longline fishing vessel or vessels in a specified fishing agreement that meets the established criteria. NMFS would monitor, attribute, and restrict catches of longline-caught bigeye tuna, including catches made under a specified fishing agreement, using the procedures and accountability measures described in the proposed rule. The longline bigeye tuna catch limit specifications would be effective in 2014.

NMFS also proposes to make technical administrative changes to certain international fisheries requirements under the Western and Central Pacific Fisheries Convention Implementation Act, to make them consistent with this proposed rule.

NMFS intends the proposed rule and specifications to implement Section 113 of the Consolidated and Further

Continuing Appropriation Act of 2012, consistent with the Magnuson-Stevens Fishery Conservation and Management Act.

DATES: In order to be considered, NMFS must receive any comments on the proposed rule and proposed specifications by February 24, 2014.

ADDRESSES: You may submit comments on the proposed rule and proposed specifications, identified by NOAA–NMFS–2012–0178, by either of the following methods:

• Electronic Submission: Submit all electronic public comments via the Federal e-Rulemaking Portal. Go to *www.regulations.gov/#!docketDetail;D=NOAA-NMFS-2012-0178*, click the ''Comment Now!'' icon, complete the required fields, and enter or attach your comments.

• Mail: Send written comments to Michael D. Tosatto, Regional Administrator, NMFS Pacific Islands Region (PIR), 1601 Kapiolani Blvd., Suite 1110, Honolulu, HI 96814–4700.

Instructions: Comments sent by any other method, to any other address or individual, or received after the end of the comment period, may not be considered by NMFS. All comments received are a part of the public record and will generally be posted for public viewing on *www.regulations.gov* without change. All personal identifying information (e.g., name, address, etc.), confidential business information, or otherwise sensitive information submitted voluntarily by the sender will be publicly accessible. NMFS will accept anonymous comments (enter ''N/A'' in the required fields if you wish to remain anonymous), and will accept attachments to electronic comments in Microsoft Word, Excel, or Adobe PDF file formats only.

The proposed rule and proposed specifications would implement Amendment 7 to the Fishery Ecosystem Plan for Pelagic Fisheries of the Western Pacific Region (Pelagics FEP). Amendment 7, which includes an environmental assessment and regulatory impact review, provides background information on the proposed rule and proposed specifications and is available from *www.regulations.gov* or the Western Pacific Fishery Management Council (Council), 1164 Bishop St., Suite 1400, Honolulu, HI 96813, tel 808–522–8220, fax 808–522–8226, *www.wpcouncil.org.*

You may submit written comments regarding the burden-hour estimates or other aspects of the collection-of-information requirements contained in this proposed rule to Michael D. Tosatto (see **ADDRESSES**) and by email to *OIRA_Submission@omb.eop.gov* or fax to 202–395–7285.

FOR FURTHER INFORMATION CONTACT: Adam Bailey, NMFS PIR Sustainable Fisheries Division, 808–944–2248.

SUPPLEMENTARY INFORMATION: NMFS and the Council manage the pelagic fisheries of American Samoa, Guam, the Commonwealth of the Northern Mariana Islands (CNMI), and Hawaii under the Pelagics FEP. Typically, the Council recommends conservation and management measures for NMFS to implement under the authority of the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act). Certain pelagic fish stocks, including tunas, are also subject to conservation and management measures cooperatively agreed to by the Western and Central Pacific Fisheries Commission (WCPFC), an international regional fisheries management organization that has jurisdiction over fisheries harvesting highly migratory species in the western and central Pacific Ocean (WCPO, generally west of 150° W. longitude). Although NMFS often implements these decisions directly under the authority of the Western and Central Pacific Fisheries Convention Implementation Act, the Council may also recommend conservation and management measures applicable to the U.S. component of internationally-managed fisheries for implementation by NMFS under the Magnuson-Stevens Act.

In 2008, the WCPFC adopted Conservation and Management Measure (CMM) 2008–01 ''Conservation and Management Measure for Bigeye and Yellowfin Tuna in the Western and Central Pacific Ocean.'' CMM 2008–01 established an annual bigeye tuna catch limit for U.S. longline fisheries operating in the WCPO, and separate longline bigeye tuna catch limits for the U.S. participating territories to the WCPFC, which are American Samoa, Guam, and the CNMI. The U.S. bigeye tuna limit was 3,763 mt, which NMFS implemented in 2009, 2010 and 2011 (December 7, 2009, 74 FR 63999). This limit applied only to Hawaii- and U.S. West Coast-based longline fisheries that fished in the WCPO; the limit did not apply to longline fisheries of the U.S. participating territories. CMM 2008–01 also provided that WCPFC members and Participating Territories of the WCPFC that caught less than 2,000 mt of bigeye tuna in 2004 would be subject to an annual limit of 2,000 mt, except that Small Island Developing States and Participating Territories of the WCPFC undertaking responsible development of their fisheries would not be subject to individual annual limits for bigeye tuna. The three U.S. participating territories fell into this category.

The WCPFC extended the U.S. bigeye tuna limit for 2012 through CMM 2011–01 (August 27, 2012, 77 FR 51709), and for fishing year 2013 through CMM 2012–01 (September 23, 2013, 78 FR 58240). In addition, under CMM 2012–01, Small Island Developing States and Participating Territories of the WCPFC, including American Samoa, Guam, and the CNMI, were not subject to individual longline limits for bigeye tuna for fishing year 2013. Subsequently, in December 2013, the WCPFC adopted a new tropical tuna conservation and management measure, which maintain the U.S. longline bigeye tuna catch limit of 3,763 mt for 2014, and reduces the limit to 3,554 mt in 2015 and 2016, and to 3,345 mt for 2017. CMM 2013–01 further provides that members that caught less than 2,000 mt of bigeye in 2004 are limited to no more than 2,000 mt in each of 2014, 2015, 2016 and 2017. However, this limit does not apply to Small Island Developing States and Participating Territories of the WCPFC. Consistent with previous WCPFC measures, the U.S. participating territories are not subject to individual longline limits for bigeye tuna under CMM 2013–01.

There are two Hawaii longline fisheries: The deep-set fishery that targets bigeye tuna, and the shallow-set fishery that targets swordfish, but also retains other pelagic management unit species (MUS), including bigeye tuna. Therefore, the U.S. bigeye tuna limit applies to both fisheries. NMFS monitors the longline catch and, when NMFS projects the fisheries will reach the U.S. bigeye tuna limit, NMFS prohibits the retention, transshipment, or landing of bigeye tuna by Hawaii longline vessels in the WCPO through the remainder of the year. NMFS restricted the fisheries in this way in 2009 and 2010.

In 2011, Congress passed Public Law 112–55, 125 Stat. 552 *et seq.,* the Consolidated and Further Continuing Appropriations Act (CFCAA), 2012. Section 113 of the CFCAA authorized the U.S. participating territories to use, assign, allocate, and manage catch or fishing effort limits agreed to by the WCPFC through fishing agreements with U.S. fishing vessels to support fisheries development in the territories, and directed NMFS to attribute pelagic MUS catches made by such vessels to the U.S. participating territory to which the agreement applies. In 2011, NMFS forecasted that the U.S. bigeye catch limit of 3,763 mt would be reached on November 17, 2011. Under the authority

of Section 113, the government of American Samoa entered into a fishing agreement with certain Hawaii longline fishing vessels for 2011 and 2012. From November 18 through December 31, 2011, NMFS attributed to American Samoa 628 mt of bigeye tuna caught by those vessels. Because of the Section 113 agreement, the U.S. bigeye tuna limit was not reached, and Hawaii longline vessels that were not part of that agreement continued to catch bigeye tuna in the WCPO under the remaining amount of the U.S. bigeye tuna limit.

In 2012, NMFS forecasted that the U.S. bigeye tuna catch limit of 3,763 mt would be reached on November 27, 2012. In accordance with NMFS regulations at 50 CFR 300.224, from November 20, 2012, through December 31, 2012, NMFS attributed to American Samoa 771 mt of bigeye tuna caught by Hawaii longline vessels in the American Samoa fishing agreement. Consequently, the U.S. bigeye tuna limit was not reached, and Hawaii longline vessels that were not part of that agreement continued to catch bigeye tuna in the WCPO under the remaining amount of the U.S. bigeye tuna limit. In both 2011 and 2012, the United States did not exceed its bigeye tuna limit of 3,763 mt, and the amount of bigeye tuna caught by Hawaii-based longline vessels and attributed to American Samoa was less than 1,000 mt each year.

In 2013, Congress extended the Section 113 provisions through Public Law 113–6, 125 Stat. 603, Section 110, the Department of Commerce Appropriations Act. For 2013, the government of the CNMI entered into a Section 113 agreement with certain Hawaii longline vessels. On December 5, 2013, in accordance with NMFS regulations at 50 CFR 300.224, NMFS began attributing to the CNMI bigeye tuna catches made by vessels identified in the agreement. The attribution is expected to continue through the end of 2013. NMFS does not expect the 2013 U.S. bigeye tuna limit of 3,763 mt to be reached.

Proposed Rule

As provided in Section 113 of the CFCAA, and based on recommendations from the Council, consistent with the Magnuson-Stevens Act, this proposed rule would implement the following:

- Establish a framework consistent with WPCFC conservation and management measures for specifying catch or fishing effort limits and accountability measures for pelagic fisheries in the U.S. participating territories, which are American Samoa, Guam, and the Northern Mariana Islands;
- Authorize each U.S. participating territory to enter into specified fishing agreements with U.S. fishing vessels permitted under the Pelagic FEP, and allocate to those vessels a specified portion of a territory's catch or fishing effort limit, as determined by NMFS and the Council;
- Establish the criteria that specified fishing agreements must satisfy, and the procedures for reviewing agreements; and
- Establish accountability measures for attributing and restricting catch and fishing effort toward specified limits, including catches and fishing effort made by vessels in the agreements.

Under the proposed rule, the Council would review existing and proposed catch or fishing effort limit specifications and the portion available for allocation at least annually to ensure consistency with the Pelagics FEP, Magnuson-Stevens Act, WCPFC decisions, and other applicable laws. Based on this review, at least annually, the Council would recommend to NMFS whether such catch or fishing effort limit specification or the portion available for allocation should be approved for the next fishing year. NMFS would review any Council recommendation and, if determined to be consistent with the Pelagics FEP, Magnuson-Stevens Act, WCPFC decisions and other applicable laws, would approve such recommendation. If NMFS determines that a recommendation is inconsistent with the Pelagics FEP, Magnuson-Stevens Act, WCPFC decisions and other applicable laws, NMFS would disapprove the recommendation and provide the Council with a written explanation of the reasons. If a catch or fishing effort limit specification or allocation limit is disapproved, or if the Council recommends and NMFS approves no catch or fishing effort limit specification or allocation limit, then no specified fishing agreements would be accepted for the fishing year covered by such action.

Proposed Specifications

In addition to the proposed framework process, NMFS also proposes to apply that process to specify a longline bigeye tuna catch limit of 2,000 mt for each U.S. participating territory. The current WCPFC Conservation and Management Measure for tropical tuna stocks (CMM 2013–01), adopted in December 2013, limits members that harvested less than 2,000 mt of bigeye in 2004 to no more than 2,000 mt for each of the years 2014 through 2017. However, paragraph 7 of CMM 2013–01 does not establish an individual limit on the amount of bigeye tuna that may be harvested annually in the WCPFC Convention Area by Small Island Developing States and Participating Territories of the WCPFC, including American Samoa, Guam, and the CNMI. NMFS and the Council, however, believe it is important that the paragraph 7 exemption not apply to U.S. participating territories, since bigeye tuna is currently subject to overfishing. Therefore, NMFS proposes to establish 2,000-mt limits for the U.S. participating territories. These limits, in conjunction with the 1,000-mt limits that may be allocated under specified fishing agreements (see below), will help ensure stock sustainability under the proposed action.

NMFS would specify that each U.S. participating territory may allocate up to 1,000 mt of its 2,000-mt bigeye tuna limit to a U.S. longline fishing vessel or vessels based in another U.S. participating territory or Hawaii, and identified in a specified fishing agreement. For U.S. fishing vessels identified in a valid specified fishing agreement that are subject to the U.S. bigeye tuna limit and fishing restrictions set forth in 50 CFR 300 Subpart O, NMFS would attribute catch made by such vessels to the applicable territory. The attribution would begin seven days before the date that NMFS projects the limit to be reached, or upon the effective date of the agreement, whichever is later. The effective date is the date upon which NMFS provides written notice to the authorized official or designated representative that the specified fishing agreement meets the requirements of this rule.

For all other U.S. fishing vessels identified in a valid specified fishing agreement, NMFS would attribute catch made by such vessels to the applicable territory beginning seven days before the date NMFS determines the limit is projected to be reached, or upon the effective date of the agreement, whichever is later. NMFS would monitor and restrict, as appropriate, catches of longline-caught bigeye tuna, including catches made under a specified fishing agreement, using the accountability measures described in the proposed rule. The longline bigeye tuna catch limit specifications would be effective for the 2014 fishing year, which is scheduled to begin on January 1, 2014.

In addition to seeking public comments on this proposed rule and associated proposed specifications, NMFS is soliciting comments on proposed Amendment 7 to the Pelagics

FEP, as stated in the Notice of Availability published on December 30, 2013 (78 FR 79388). NMFS must receive comments on Amendment 7 by February 28, 2014. The Secretary of Commerce will consider public comments on this proposed rule and proposed specifications in the decision to approve, disapprove, or partially approve Amendment 7.

Classification

Pursuant to section 304(b)(1)(A) of the Magnuson-Stevens Act, the NMFS Assistant Administrator has determined that the proposed action is consistent with the Pelagics FEP, other provisions of the Magnuson-Stevens Act, and other applicable laws, subject to further consideration after public comment.

Executive Order 12866

This proposed rule has been determined to be not significant for purposes of Executive Order 12866.

Certification Under the Regulatory Flexibility Act

The Chief Council for Regulation of the Department of Commerce certified to the Chief Council for Advocacy of the Small Business Administration that this proposed action, if adopted, would not have a significant economic impact on a substantial number of small entities. A description of the action, why it is being considered, and the legal basis for this action are contained in the preamble to this proposed rule.

In 2011, the U.S. Congress passed Public Law 112–55, 125 Stat. 552 *et seq.,* the Consolidated and Further Continuing Appropriations Act (CFCAA), 2012. Section 113 of the CFCAA allows the U.S. participating territories (i.e., American Samoa, Guam, and the CNMI) of the WCPFC to use, assign, allocate, and manage catch limits of highly migratory fish stocks, or fishing effort limits agreed to by the WCPFC through fishing agreements with fishing vessels of the United States for the purpose of supporting fisheries development in those territories. Section 113 also authorizes NMFS to attribute catches made by such vessels to the U.S. participating territory to which the agreement applies. Section 113, as extended through the end of 2013 by Public Law 113–6, 125 Stat. 603, Section 110, the Department of Commerce Appropriations Act, also directed the Council to amend the Pelagics FEP to implement these provisions under the plan. The proposed action intends to implement Section 113 of the CFCAA through Amendment 7 to the Pelagics FEP, consistent with the Magnuson-Stevens Act.

This proposed action would directly apply to vessels federally permitted under the Pelagics FEP, specifically Hawaii longline limited entry, American Samoa longline limited entry, Western Pacific general longline, Pacific Remote Island Areas (PRIA) troll and handline, and Western Pacific Pelagic squid jig permit holders. As of August 2013, 131 vessels possessed Hawaii longline limited entry permits (out of 164 total permits), 47 possessed American Samoa longline limited entry permits (out of 60 total permits), no vessels held Western Pacific general longline permits, five vessels held Pacific Remote Island Areas (PRIA) troll and handline permits, and one held a Western Pacific pelagic squid jig permit. Among the American Samoa and Hawaii longline vessels with limited entry permits in August 2013, 16 held both American Samoa and Hawaii longline limited entry permits (dual permit holders).

According to landings information provided in the environmental assessment in support of this action and logbook information, Hawaii-based longline vessels landed approximately 25,866,000 lb of pelagic fish valued at $94,901,000 in 2012 (see Tables 7 and 8 of Amendment 7). These vessels made 1,437 trips, caught 159,787 bigeye tuna, and kept 157,502, along with other pelagic fish. With 129 vessels making either a deep- or shallow-set trip that year, the ex-vessel value of pelagic fish caught by Hawaii-based longline fisheries averaged about $736,000 per vessel. In 2012, 25 American Samoa longline vessels turned in logbooks reporting the landing of 255,686 pelagic fish valued at $9,793,153, of which almost $7.7 million came from albacore tuna landings. With 25 active longline vessels, the ex-vessel value of pelagic fish caught by the American Samoa longline fishery averaged about $391,720 per vessel.

With respect to non-longline pelagic fisheries, NMFS requires federal permits only for pelagic troll and handline vessels fishing in the PRIA and squid jig vessels. Assuming average landings of pelagic species by all pelagic troll and handline vessels in the western Pacific reflect landings made by those vessels possessing PRIA troll and handline permits, annual revenues earned from landings of pelagic species are not expected to exceed $10,000 for a typical vessel. Information on catch or revenue from the one federally permitted squid jig vessel is considered confidential and cannot be publicly reported.

On June 20, 2013, the Small Business Administration (SBA) issued a final rule revising the small business size standards for several industries effective July 22, 2013 (78 FR 37398). 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. Based on available information, NMFS has determined that all vessels federally permitted under Pelagics FEP are small entities under the SBA definition of a small entity, i.e., they are engaged in the business of fish harvesting, are independently owned or operated, are not dominant in their field of operation, and have annual gross receipts not in excess of $19 million. Therefore, there would be no disproportionate economic impacts between large and small entities. Furthermore, there would be no disproportionate economic impacts among the universe of vessels based on gear, home port, or vessel length.

Pursuant to the Regulatory Flexibility Act, NMFS has reviewed the analyses prepared for this action in light of the new size standards. Under the former, lower size standards, all vessels subject to this action were considered small entities, and they all would continue to be considered small under the new standards. NMFS does not think that the new size standards affect analyses prepared for this action and solicits public comments on the analyses in light of the new size standards.

Even though this proposed action would apply to a substantial number of vessels, the implementation of this action would not result in significant adverse economic impact to individual vessels. While the proposed framework would potentially apply to any highly migratory species under the Pelagics FEP that is subject to annual catch or fishing effort limits in the WCPO, in recent years, bigeye tuna has been the only species subject to these limits. Therefore, the discussion on impacts will center on bigeye tuna catch and longline fisheries.

The proposed action would potentially benefit Hawaii-based longline fishery participants, including dual permit holders that possess an American Samoa and Hawaii longline limited entry permit. The benefits to these vessels come through allowing the territorial fishing agreements, similar to those authorized under Section 113, to continue under the Pelagics FEP. In 2011 and 2012, American Samoa entered into a Section 113 agreement with almost all Hawaii longline fishery participants, under a framework that was similar to that proposed here. In both years, NMFS projected that the U.S. bigeye tuna limit of 3,763 mt would

be reached in mid to late November. Within seven days of the date that NMFS projected the fishery would reach the U.S. bigeye tuna limit, NMFS began attributing to American Samoa, bigeye tuna catches made by longline vessels identified in the Section 113 agreement. Under regulations at 50 CFR 300 Subpart O, vessels that possess both Hawaii and American Samoa limited entry permits are allowed to land bigeye tuna in Hawaii that was caught outside the U.S. EEZ around Hawaii, after the date that the U.S. bigeye tuna limit is projected to be reached. However, under the Section 113 agreement with American Samoa, these vessels are also allowed to land bigeye tuna in Hawaii that was caught inside the U.S. EEZ around Hawaii after the projection date. The 2011 and 2012 fishing agreement with American Samoa allowed the Hawaii-based longline fishery to land 628 mt and 771 mt of bigeye tuna, respectively, after the date NMFS projected the U.S. bigeye tuna limit would be reached.

For fishing year 2013, the CNMI entered into a Section 113 agreement with certain Hawaii longline fishery participants. NMFS projected that the U.S. bigeye tuna limit of 3,763 mt would be reached in early December, and on December 5, 2013, began attributing to the CNMI bigeye tuna catches made by vessels identified in the Section 113 agreement. The attribution will continue through the end of December 2013.

Based on catch and fishing effort under the 2011 and 2012 fishing agreement, it is likely that under the proposed action, less than 1,000 mt of bigeye tuna would be harvested by Hawaii vessels identified in a specified fishing agreement for 2014. Providing opportunity to land bigeye tuna in Hawaii in the last quarter of the year when market demand is significant will result in positive economic benefits for fishery participants and net benefits to the nation. In terms of the impacts of reducing the limits of bigeye tuna catch by longline vessels based in the territories from an unlimited amount to 2,000 mt, this is not likely to adversely affect vessels based in the territories.

Historical catch of bigeye tuna attributed to American Samoa has been less than 2,000 mt, even when including catch by vessels based in American Samoa, catch attributed by U.S. vessels (in 2011 and 2012), and dual permitted vessels. There appears to have been little, if any, catch of bigeye tuna by longline vessels in Guam or CNMI in recent years.

Under the proposed action, longline fisheries managed under the Pelagics FEP are not expected to expand substantially nor change the manner in which they are currently conducted, (i.e., area fished, number of vessels longline fishing, number of trips taken per year, number of hooks set per vessel during a trip, depth of hooks, or deployment techniques in setting longline gear), due to existing operational constraints in the fleet, the limited entry permit programs, and protected species mitigation requirements. The likely scenario under the proposed action is expected to result fishing similar to what occurred in 2011 and 2012 under Section 113 fishing agreements.

The proposed rule does not duplicate, overlap, or conflict with other Federal rules and is not expected to have significant impact on small entities (as discussed above), organizations or government jurisdictions. There does not appear to be disproportionate economic impacts from the proposed rule based on home port, gear type, or relative vessel size. The proposed rule also will not place a substantial number of small entities, or any segment of small entities, at a significant competitive disadvantage to large entities.

For the reasons above, NMFS does not expect the proposed action to have a significant economic impact on a substantial number of small entities. As a result, an initial regulatory flexibility analysis is not required and none has been prepared.

Paperwork Reduction Act

This proposed rule contains a collection-of-information requirement subject to review and approval by OMB under the Paperwork Reduction Act (PRA). This requirement has been submitted to OMB for approval. The public reporting burden for a specified fishing agreement is estimated to average six hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection information. NMFS expects to receive up to nine applications for specified fishing agreements each year, for a total maximum reporting burden of 54 hours per year.

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 Michael D. Tosatto (see **ADDRESSES**), and by email to *OIRA_Submission@omb.eop.gov* or by fax to 202–395–7285.

List of Subjects

50 CFR Part 300

Administrative practice and procedure, Fish, Fisheries, Fishing, Marine resources, Reporting and recordkeeping requirements, Treaties.

50 CFR Part 665

Administrative practice and procedure, American Samoa, Commercial fishing, Fisheries, Guam, Hawaii, Northern Mariana Islands, Western and Central Pacific Fisheries Commission.

Dated: December 31, 2013.

Alan D. Risenhoover,

Director, Office of Sustainable Fisheries, performing the functions and duties of the Deputy Assistant Administrator for Regulatory Programs, National Marine Fisheries Service.

For the reasons set out in the preamble, NMFS proposes to amend 50 CFR parts 300 and 665 as follows:

PART 300—INTERNATIONAL FISHERIES REGULATIONS

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

Authority: 16 U.S.C. 6901 *et seq.*

■ 2. In § 300.224, remove paragraph (g) and revise paragraphs (d) and (f)(1)(iv) to read as follows:

§ 300.224 Longline fishing restrictions.

* * * * *

(d) *Exception for bigeye tuna caught by vessels included in specified fishing agreements under § 665.819(c) of this title.* Bigeye tuna caught by a vessel that is included in a specified fishing agreement under § 665.819(c) of this title will be attributed to the longline fishery of American Samoa, Guam, or the Northern Mariana Islands, according to the terms of the agreement to the extent the agreement is consistent with § 665.819(c) of this title and other applicable laws, and will not be counted against the limit, provided that:

(1) The start date specified in § 665.819(c)(9)(i) of this title has occurred or passed; and

(2) NMFS has not made a determination under § 665.819(c)(9)(iii) of this title that the catch of bigeye tuna

exceeds the limit allocated to the territory that is a party to the agreement.

* * * * *

(f) * * *

(1) * * *

(iv) Bigeye tuna caught by longline gear may be retained on board, transshipped, and/or landed if they were caught by a vessel that is included in a specified fishing agreement under § 665.819(c) of this title, if the agreement provides for bigeye tuna to be attributed to the longline fishery of American Samoa, Guam, or the Northern Mariana Islands, provided that:

(A) The start date specified in § 665.819(c)(9)(i) of this title has occurred or passed; and

(B) NMFS has not made a determination under § 665.819(c)(9)(iii) of this title that the catch of bigeye tuna exceeds the limit allocated to the territory that is a party to the agreement.

* * * * *

PART 665—FISHERIES IN THE WESTERN PACIFIC

■ 3. The authority citation for part 665 continues to read as follows:

Authority: 16 U.S.C. 1801 *et seq.*

■ 4. In § 665.800, add new definitions of ''Effective date,'' ''U.S. participating territory,'' and ''WCPFC'' in alphabetical order to read as follows:

§ 665.800 Definitions.

* * * * *

Effective date means the date upon which the Regional Administrator provides written notice to the authorized official or designated representative of the U.S. participating territory that a specified fishing agreement meets the requirements of this section.

* * * * *

U.S. participating territory means a U.S. participating territory to the Convention on the Conservation and Management of Highly Migratory Fish Stocks in the Western and Central Pacific Ocean (including any annexes, amendments, or protocols that are in force, or have come into force, for the United States), and includes American Samoa, Guam, and the Northern Mariana Islands.

* * * * *

WCPFC means the Commission for the Conservation and Management of Highly Migratory Fish Stocks in the Western and Central Pacific Ocean, including its employees and contractors.

* * * * *

■ 5. In § 665.802, add paragraph (o) to read as follows:

§ 665.802 Prohibitions.

* * * * *

(o) Use a fishing vessel to retain on board, transship, or land pelagic MUS captured by longline gear in the WCPFC Convention Area, as defined in § 300.211 of this title, in violation of any restriction announced in accordance with § 665.819(d)(2).

* * * * *

■ 6. Add § 665.819 to subpart F to read as follows:

§ 665.819 Territorial catch and fishing effort limits.

(a) *General.* (1) Notwithstanding § 665.4, if the WCPFC agrees to a catch or fishing effort limit for a stock of western Pacific pelagic MUS that is applicable to a U.S. participating territory, the Regional Administrator may specify an annual or multi-year catch or fishing effort limit for a U.S. participating territory, as recommended by the Council, not to exceed the WCPFC adopted limit. The Regional Administrator may authorize such U.S. participating territory to allocate a portion, as recommended by the Council, of the specified catch or fishing effort limit to a fishing vessel or vessels holding a valid permit issued under § 665.801 through a specified fishing agreement pursuant to paragraph (c) of this section.

(2) If the WCPFC does not agree to a catch or fishing effort limit for a stock of western Pacific pelagic MUS applicable to a U.S. participating territory, the Council may recommend that the Regional Administrator specify such a limit that is consistent with the Pelagics FEP, other provisions of the Magnuson-Stevens Act, and other applicable laws. The Council may also recommend that the Regional Administrator authorize a U.S. participating territory to allocate a portion of a specified catch or fishing effort limit to a fishing vessel or vessels holding valid permits issued under § 665.801 through a specified fishing agreement pursuant to paragraph (c) of this section.

(3) The Council shall review any existing or proposed catch or fishing effort limit specification and portion available for allocation at least annually to ensure consistency with the Pelagics FEP, Magnuson-Stevens Act, WCPFC decisions, and other applicable laws. Based on this review, at least annually, the Council shall recommend to the Regional Administrator whether such catch or fishing effort limit specification or portion available for allocation should be approved for the next fishing year.

(4) The Regional Administrator shall review any Council recommendation pursuant to paragraph (a) of this section and, if determined to be consistent with the Pelagics FEP, Magnuson-Stevens Act, WCPFC decisions, and other applicable laws, shall approve such recommendation. If the Regional Administrator determines that a recommendation is inconsistent with the Pelagics FEP, Magnuson-Stevens Act, WCPFC decisions and other applicable laws, the Regional Administrator would disapprove the recommendation and provide the Council with a written explanation of the reasons for disapproval. If a catch or fishing effort limit specification or allocation limit is disapproved, or if the Council recommends and NMFS approves no catch or fishing effort limit specification or allocation limit, no specified fishing agreements as described in paragraph (c) of this section will be accepted for the fishing year covered by such action.

(b) *Procedures and timing.* (1) After receiving a Council recommendation for a catch or fishing effort limit specification, or portion available for allocation, the Regional Administrator will evaluate the recommendation for consistency with the Pelagics FEP, other provisions of the Magnuson-Stevens Act, and other applicable laws.

(2) The Regional Administrator will publish in the **Federal Register** a notice and request for public comment of the proposed catch or fishing effort limit specification and any portion of the limit that may be allocated to a fishing vessel or vessels holding a valid permit issued under § 665.801.

(3) The Regional Administrator will publish in the **Federal Register**, and will use other reasonable methods to notify permit holders, a notice of the final catch or fishing effort limit specification and portion of the limit that may be allocated to a fishing vessel or vessels holding valid permits issued under § 665.801. The final specification of a catch or fishing effort limit will also announce the deadline for submitting a specified fishing agreement for review as described in paragraph (c) of this section. The deadline will be no earlier than 30 days after the publication date of the **Federal Register** notice that specifies the final catch or fishing effort limit and the portion of the limit that may be allocated through a specified fishing agreement.

(c) *Specified fishing agreements.* A specified fishing agreement means an agreement between a U.S. participating territory and the owner or a designated representative of a fishing vessel or vessels holding a valid permit issued

under § 665.801 of this part. An agreement provides access to an identified portion of a catch or fishing effort limit and may not exceed the amount specified for the territory and made available for allocation pursuant to paragraph (a) of this section. The identified portion of a catch or fishing effort limit in an agreement must account for recent and anticipated harvest on the stock or stock complex or fishing effort, and any other valid agreements with the territory during the same year not to exceed the territory's catch or fishing effort limit or allocation limit.

(1) An authorized official or designated representative of a U.S. participating territory may submit a complete specified fishing agreement to the Council for review. A complete specified fishing agreement must meet the following requirements:

(i) Identify the vessel(s) to which the fishing agreement applies, along with documentation that such vessel(s) possesses a valid permit issued under § 665.801;

(ii) Identify the amount of western Pacific pelagic MUS to which the fishing agreement applies, if applicable;

(iii) Identify the amount of fishing effort to which the fishing agreement applies, if applicable;

(iv) Be signed by an authorized official of the applicable U.S. participating territory, or designated representative;

(v) Be signed by each vessel owner or designated representative; and

(vi) Satisfy either paragraph (c)(1)(vi)(A) or (B) of this section:

(A) Require the identified vessels to land or offload catch in the ports of the U.S. participating territory to which the fishing agreement applies; or

(B) Specify the amount of monetary contributions that each vessel owner in the agreement, or his or her designated representative, will deposit into the Western Pacific Sustainable Fisheries Fund;

(vii) Be consistent with the Pelagics FEP and implementing regulations, the Magnuson-Stevens Act, and other applicable laws; and

(viii) Shall not confer any right of compensation to any party enforceable against the United States should action under such agreement be prohibited or limited by NMFS pursuant to its authority under Magnuson-Stevens Act, or other applicable laws.

(2) *Council review.* The Council, through its Executive Director, will review a submitted specified fishing agreement to ensure that it is consistent with paragraph (c)(1) of this section. The Council will advise the authorized official or designated representative of the U.S. participating territory to which the agreement applies of any inconsistency and provide an opportunity to modify the agreement, as appropriate. The Council will transmit the complete specified fishing agreement to the Regional Administrator for review.

(3) *Agency review.* (i) Upon receipt of a specified fishing agreement from the Council, the Regional Administrator will consider such agreement for consistency with paragraph (c)(1) of this section, the Pelagics FEP and implementing regulations, the Magnuson-Stevens Act, and other applicable laws.

(ii) Within 30 calendar days of receipt of the fishing agreement from the Council, the Regional Administrator will provide the authorized official or designated representative of the U.S. participating territory to which the agreement applies with written notice of whether the agreement meets the requirements of this section. The Regional Administrator will reject an agreement for any of the following reasons:

(A) The agreement fails to meet the criteria specified in this subpart;

(B) The applicant has failed to disclose material information;

(C) The applicant has made a material false statement related to the specified fishing agreement;

(D) The agreement is inconsistent with the Pelagics FEP, implementing regulations, the Magnuson-Stevens Act, or other applicable laws; or

(E) The agreement includes a vessel identified in another valid specified fishing agreement.

(iii) The Regional Administrator, in consultation with the Council, may recommend that specified fishing agreements include such additional terms and conditions as are necessary to ensure consistency with the Pelagics FEP and implementing regulations, the Magnuson-Stevens Act, and other applicable laws.

(iv) The U.S. participating territory must notify NMFS and the Council in writing of any changes in the identity of fishing vessels to which the specified fishing agreement applies within 72 hours of the change.

(v) Upon written notice that a specified fishing agreement fails to meet the requirements of this section, the Regional Administrator may provide the U.S. participating territory an opportunity to modify the fishing agreement within the time period prescribed in the notice. Such opportunity to modify the agreement may not exceed 30 days following the date of written notice. The U.S. participating territory may resubmit the agreement according to paragraph (c)(1) of this section.

(vi) The absence of the Regional Administrator's written notice within the time period specified in paragraph (c)(3)(ii) of this section or, if applicable, within the extended time period specified in paragraph (c)(3)(v) of this section shall operate as the Regional Administrator's finding that the fishing agreement meets the requirements of this section.

(4) *Transfer.* Specified fishing agreements authorized under this section are not transferable or assignable, except as allowed pursuant to paragraph (c)(3)(iv) of this section.

(5) A vessel shall not be identified in more than one valid specified fishing agreement at a time.

(6) *Revocation and suspension.* The Regional Administrator, in consultation with the Council, may at any time revoke or suspend attribution under a specified fishing agreement upon the determination that either: Operation under the agreement would violate the requirements of the Pelagics FEP or implementing regulations, the Magnuson-Stevens Act, or other applicable laws; or the U.S. participating territory fails to notify NMFS and the Council in writing of any changes in the identity of fishing vessels to which the specified fishing agreement applies within 72 hours of the change.

(7) *Cancellation.* The U.S. participating territory and the vessel owner(s), or designated representative(s), that are party to a specified fishing agreement must notify the Regional Administrator in writing within 72 hours after an agreement is cancelled or no longer valid. A valid notice of cancellation shall require the signatures of both parties to the agreement. All catch or fishing effort attributions under the agreement shall cease upon the written date of a valid notice of cancellation.

(8) *Appeals.* An authorized official or designated representative of a U.S. participating territory may appeal the granting, denial, conditioning, or suspension of a specified fishing agreement affecting their interests to the Regional Administrator in accordance with the permit appeals procedures set forth in 665.801(o) of this subpart.

(9) *Catch or fishing effort attribution procedures.* (i) For vessels identified in a valid specified fishing agreement that are subject to the U.S. bigeye tuna limit and fishing restrictions set forth in 50 CFR part 300, subpart O, NMFS will attribute catch made by such vessels to the applicable U.S. participating

territory starting seven days before the date NMFS projects the annual U.S. bigeye tuna limit to be reached, or upon the effective date of the agreement, whichever is later.

(ii) For U.S. fishing vessels identified in a valid specified fishing agreement that are subject to catch or fishing effort limits and fishing restrictions set forth in this subpart, NMFS will attribute catch or fishing effort to the applicable U.S. participating territory starting seven days before the date NMFS projects the limit to be reached, or upon the effective date of the agreement, whichever is later.

(iii) If NMFS determines catch or fishing effort made by fishing vessels identified in a specified fishing agreement exceeds the allocated limit, NMFS will attribute any overage of the limit back to the U.S. or Pacific island fishery to which the vessel(s) is registered and permitted in accordance with the regulations set forth in 50 CFR part 300, subpart O and other applicable laws.

(d) *Accountability measures.* (1) NMFS will monitor catch and fishing effort with respect to any territorial catch or fishing effort limit, including the amount of a limit allocated to vessels identified in a valid specified fishing agreement, using data submitted in logbooks and other information. When NMFS projects a territorial catch or fishing effort limit or allocated limit to be reached, the Regional Administrator shall publish notification to that effect in the **Federal Register** at least seven days before the limit will be reached and shall use other reasonable means to notify permit holders.

(2) The notice will include an advisement that fishing for the applicable pelagic MUS stock or stock complex, or fishing effort, will be restricted on a specific date. The restriction may include, but is not limited to, a prohibition on retention, closure of a fishery, closure of specific areas, or other catch or fishing effort restrictions. The restriction will remain in effect until the end of the fishing year.

(e) *Disbursement of contributions from the Sustainable Fisheries Fund.* (1) NMFS shall make available to the Western Pacific Fishery Management Council monetary contributions, made to the Fund pursuant to a specified fishing agreement, in the following order of priority:

(i) Project(s) identified in an approved Marine Conservation Plan (16 U.S.C. 1824) of a U.S. participating territory that is a party to a valid specified fishing agreement, pursuant to § 665.819(c); and

(ii) In the case of two or more valid specified fishing agreements in a fishing year, the projects listed in an approved Marine Conservation Plan applicable to the territory with the earliest valid agreement will be funded first.

(2) At least seven calendar days prior to the disbursement of any funds, the Council shall provide in writing to NMFS a list identifying the order of priority of the projects in an approved Marine Conservation Plan that are to be funded. The Council may thereafter revise this list.

[FR Doc. 2013–31592 Filed 1–2–14; 11:15 am]

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Notices

Federal Register

Vol. 79, No. 5

Wednesday, January 8, 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 COMMERCE

International Trade Administration

[A–583–837]

Polyethylene Terephthalate Film From Taiwan: Partial Rescission of Antidumping Duty Administrative Review; 2012–2013

AGENCY: Enforcement and Compliance, formerly Import Administration, International Trade Administration, Department of Commerce.

DATES: *Effective Date:* January 8, 2014.

FOR FURTHER INFORMATION CONTACT: Toni Page, Enforcement and Compliance, AD/CVD Operations, Office VII, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue NW., Washington, DC 20230; telephone: (202) 482–1398.

Background

On July 2, 2013, the Department of Commerce (the Department) published a notice of opportunity to request an administrative review of the antidumping duty (AD) order on polyethylene terephthalate film (PET film) from Taiwan covering the period July 1, 2012 through June 30, 2013.[1] The Department received a timely request from Petitioners [2] for an AD administrative review of two companies: Nan Ya Plastics Corporation (Nan Ya) and Shinkong Materials Technology Corporation (Shinkong).[3] Nan Ya also timely requested a review of itself.[4] On August 28, 2013, the Department published a notice of initiation of an administrative review of the AD order on PET film from Taiwan with respect to Nan Ya and Shinkong.[5] On December 12, 2013, Petitioners timely withdrew their request for reviews of both Nan Ya and Shinkong.[6]

Rescission, in Part

Pursuant to 19 CFR 351.213(d)(1), the Department will rescind an administrative review, in whole or in part, if a party that requested the review withdraws the request within 90 days of the date of publication of the notice of initiation of the requested review. Petitioners timely submitted a withdrawal request within the 90-day period (*i.e.,* before December 12, 2013).[7] Because Shinkong did not request a review for itself, we are rescinding this administrative review of the AD order on PET film from Taiwan for this company, consistent with 19 CFR 351.213(d)(1). Nan Ya did not submit a withdrawal request; therefore, we will proceed with an administrative review of this company.

Assessment

The Department will instruct U.S. Customs and Border Protection (CBP) to assess ADs on all appropriate entries. Shinkong shall be assessed ADs at rates equal to the cash deposit of estimated ADs required at the time of entry, or withdrawal from warehouse, for consumption, during the period July 1, 2012, through June 30, 2013, in accordance with 19 CFR 351.212(c)(1)(i). The Department intends to issue appropriate assessment instructions to CBP 15 days after publication of this notice.

Notification Regarding Administrative Protective Orders

This notice also serves as a reminder to parties subject to the administrative protective order (APO) of their responsibility concerning the disposition of proprietary information disclosed under an APO in accordance with 19 CFR 351.305(a)(3), which continues to govern business proprietary information in this segment of the proceeding. Timely written notification of the return or destruction of APO materials, or conversion to judicial protective order, is hereby requested. Failure to comply with the regulations and terms of an APO is a violation which is subject to sanction.

This notice is issued and published in accordance with sections 751(a)(1) and 777(i)(1) of the Tariff Act of 1930, as amended, and 19 CFR 351.213(d)(4).

Dated: January 2, 2014.

Christian Marsh,

Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations.

[FR Doc. 2014–00111 Filed 1–7–14; 8:45 am]

BILLING CODE 3510–DS–P

[1] *See Antidumping or Countervailing Duty Order, Finding, or Suspended Investigation; Opportunity To Request Administrative Review,* 78 FR 39710 (July 2, 2013).

[2] Petitioners are DuPont Teijin Films, Mitsubishi Polyester Film, Inc., and SKC, Inc.

[3] *See* Letter to the Department from Petitioners ''Polyethylene Terephthalate (PET) Film, Sheet, and Strip from Taiwan: Request for Antidumping Duty Administrative Review'' (July 31, 2013).

[4] *See* Letter to the Department from Nan Ya Re: Polyethylene Terephthalate (PET) Film from Taiwan (July 31, 2013).

[5] *See Initiation of Antidumping and Countervailing Duty Administrative Reviews and Requests for Revocation in Part,* 78 FR 53128 (August 28, 2013).

[6] *See* Letter to the Department from Petitioners ''Polyethylene Terephthalate (PET) Film, Sheet, and Strip from Taiwan: Withdrawal of Request for Antidumping Duty Administrative Review'' (December 12, 2013).

[7] As explained in the memorandum from the Assistant Secretary for Enforcement and Compliance, the Department exercised its discretion to toll deadlines for the duration of the closure of the Federal Government from October 1, through October 16, 2013. *See* Memorandum for the Record from Paul Piquado, Assistant Secretary for Enforcement and Compliance, ''Deadlines Affected by the Shutdown of the Federal Government'' (October 18, 2013). Therefore, all deadlines in this segment of the proceeding were extended by 16 days, thus extending the deadline for filing a withdrawal request from November 26, 2013, until December 12, 2013.

DEPARTMENT OF COMMERCE

International Trade Administration

[A–570–905]

Certain Polyester Staple Fiber From the People's Republic of China: Partial Rescission of the Antidumping Duty Administrative Review; 2012–2013

AGENCY: Enforcement and Compliance, formerly Import Administration, International Trade Administration, Department of Commerce.

SUMMARY: The Department of Commerce (''the Department'') is partially rescinding the administrative review of the antidumping duty order on certain polyester staple fiber from the People's Republic of China (''PRC'') for the period June 1, 2012 through May 31, 2013, based on the withdrawal of a certain request for review.

DATES: *Effective Date:* January 8, 2014.

FOR FURTHER INFORMATION CONTACT: Steven Hampton, AD/CVD Operations,

Office V, Enforcement and Compliance, International Trade Administration, Department of Commerce, 14th Street and Constitution Avenue NW, Washington, DC 20230; telephone: (202) 482–0116.

SUPPLEMENTARY INFORMATION:

Background

On June 3, 2013, the Department published a notice of opportunity to request an administrative review of the antidumping duty order on certain polyester staple fiber from the PRC.[1] Pursuant to requests from interested parties, the Department initiated an administrative review with respect to two exporters[2] for the period June 1, 2012 through May 31, 2013.[3] The deadline for a party to withdraw a request for review was October 30, 2013.[4] As explained in the memorandum from the Assistant Secretary for Enforcement and Compliance, the Department exercised its discretion to toll deadlines for the duration of the closure of the Federal Government from October 1, through October 16, 2013.[5] Thus, all of the deadlines in this segment of the proceeding were extended by 16 days. Therefore, the revised deadline for a party to withdraw a request for review was November 15, 2013.

Withdrawal of Review Request

On November 14, 2013, Zhaoqing Tifo New Fiber Co., Ltd. (''Zhaoqing Tifo'')[6] withdrew its review request. No other party requested an administrative review of Zhaoqing Tifo.

Partial Rescission of the 2012–2013 Administrative Review

Pursuant to 19 CFR 351.213(d)(1), the Department will rescind an administrative review, in whole or in part, if the parties that requested a review withdraw the request within 90 days of the date of publication of the notice of initiation. Zhaoqing Tifo's withdrawal of its review request was submitted within the deadline set forth under 19 CFR 351.213(d)(1). Therefore, in accordance with 19 CFR 351.213(d)(1) and consistent with our practice,[7] the Department is rescinding this review on the antidumping duty order on certain polyester staple fiber from the PRC with respect to Zhaoqing Tifo. The review will continue with respect to the other firm for which a review was requested and initiated, Takayasu.

Assessment

The Department will instruct U.S. Customs and Border Protection (''CBP'') to assess antidumping duties on all appropriate entries. For Zhaoqing Tifo, antidumping duties shall be assessed at rates equal to the cash deposit of estimated antidumping duties required at the time of entry, or withdrawal from warehouse, for consumption, during the period June 1, 2012, through May 31, 2013, in accordance with 19 CFR 351.212(c)(1)(i). The Department intends to issue appropriate assessment instruction directly to CBP 15 days after publication of this notice.

Notifications

This notice serves as a final reminder to importers of their responsibility under 19 CFR 351.402(f)(2) to file a certificate regarding the reimbursement of antidumping duties prior to liquidation of the relevant entries during this review period. Failure to comply with this requirement could result in the presumption that reimbursement of antidumping duties occurred and the subsequent assessment of doubled antidumping duties.

This notice also serves as a final reminder to parties subject to the administrative protective order (''APO'') of their responsibility concerning the disposition of proprietary information disclosed under an APO in accordance with 19 CFR 351.305(a)(3). Timely written notification of the return or destruction of APO materials, or conversion to judicial protective order, is hereby requested. Failure to comply with the regulations and terms of an APO is a violation which is subject to sanction.

Dated: January 2, 2014.

Christian Marsh,

Deputy Assistant Secretary for Antidumping and Countervailing Duty Operations.

[FR Doc. 2014–00109 Filed 1–7–14; 8:45 am]

BILLING CODE 3510–DS–P

[1] *See Antidumping or Countervailing Duty Order, Finding, or Suspended Investigation; Opportunity To Request Administrative Review,* 78 FR 33061 (June 3, 2013).

[2] The Department initiated a review of Takayasu Industrial (Jiangyin) Co., Ltd. (''Takayasu'') and Zhaoqing Tifo New Fibre Co., Ltd. (''Zhaoqing Tifo'').

[3] *See Initiation of Antidumping and Countervailing Duty Administrative Reviews and Request for Revocation in Part,* 78 FR 46566 (August 1, 2013)

[4] *Id.,* 78 FR at 46566–46567.

[5] *See* Memorandum for the Record from Paul Piquado, Assistant Secretary for Enforcement and Compliance, ''Deadlines Affected by the Shutdown of the Federal Government'' (October 18, 2013).

[6] Zhaoqing Tifo New Fiber Co., Ltd. is also known as Zhaoqing Tifo New Fibre Co., Ltd. *See, e.g.,* Letter from Zhaoqing Tifo regarding Certain Polyester Staple Fiber from the People's Republic of China Request for Annual Administrative Review, dated June 28, 2013 (Throughout this proceeding, Zhaoqing Tifo has used the different spellings of ''Fiber'' and ''Fibre'' interchangeably.)

[7] *See, e.g., Certain Lined Paper Products From India: Notice of Partial Rescission of Antidumping Duty Administrative Review and Extension of Time Limit for the Preliminary Results of Antidumping Duty Administrative Review,* 74 FR 21781 (May 11, 2009); and *Aluminum Extrusions From the People's Republic of China: Notice of Partial Rescission of Countervailing Duty Administrative Review,* 77 FR 65671 (October 30, 2012).

DEPARTMENT OF COMMERCE

National Telecommunications and Information Administration

[Docket Number: 131219999–3999–01]

RIN 0660–XC009

First Responder Network Authority; National Environmental Policy Act Implementing Procedures and Categorical Exclusions

AGENCY: National Telecommunications and Information Administration, U.S. Department of Commerce.

ACTION: Notice, Request for Public Comment.

SUMMARY: The First Responder Network Authority (FirstNet) publishes this notice to request public comments on its proposed procedures for implementing the National Environmental Policy Act (NEPA). These proposed NEPA implementing procedures are necessary to assist FirstNet in establishing an NEPA compliance program and applying the appropriate level of NEPA review for activities undertaken by FirstNet in the design, construction and operation of the nationwide interoperable public safety broadband network (PSBN).

DATES: Comments on the proposed procedures must be received by February 7, 2014.

ADDRESSES: The public is invited to submit written comments in electronic form. Written comments may be submitted by email to *FirstNetNEPAcomments@ntia.doc.gov* or mail (to the address listed below). All comments submitted in electronic form should be in a standard format such as Word or PDF. All comments submitted via mail should include, to the extent available, an electronic copy of the submission. However, paper copies of the comments will be accepted. All comments received will be made a part of the public record and may be posted to NTIA's Web site (*http://www.ntia.doc.gov/category/firstnet*) without change. All personally identifiable information (*e.g.,* name, address) voluntarily submitted by the commenter may be publicly accessible. Do not submit confidential business

information or otherwise sensitive or protected information.

FOR FURTHER INFORMATION CONTACT: Eli Veenendaal, National Telecommunications and Information Administration, U.S. Department of Commerce, 1401 Constitution Avenue NW., HCHB Room 4713, Washington, DC 20230; (202) 482–2188; or *eveenendaal@ntia.doc.gov.*

SUPPLEMENTARY INFORMATION:

I. National Environmental Policy Act

The National Environmental Policy Act of 1969 (42 U.S.C. 4321–4347) (NEPA) requires federal agencies to undertake an assessment of environmental effects of their proposed actions prior to making a final decision and implementing the action. NEPA requirements apply to any federal project, decision, or action that may have a significant impact on the quality of the human environment. NEPA also establishes the Council on Environmental Quality (CEQ), which issued regulations implementing the procedural provisions of NEPA. Among other considerations, CEQ regulations require federal agencies at 40 CFR 1507.3 to adopt their own implementing procedures to supplement CEQ's regulations implementing NEPA and to consult with CEQ during their development and prior to publication in the **Federal Register**.

The Middle Class Tax Relief and Job Creation Act of 2012 (Pub. L. 112–96, 126 Stat. 156 (2012)) (Act) creates and authorizes FirstNet to take all actions necessary to ensure the design, construction, and operation of a nationwide interoperable nationwide, public safety broadband network (PSBN) based on a single, national network architecture. The Act meets a long-standing and critical national infrastructure need to create a single, nationwide interoperable PSBN that will, for the first time, allow police officers, fire fighters, emergency medical service professionals and other public safety officials to effectively communicate with each other across agencies and jurisdictions.

As a newly created entity, FirstNet does not currently have procedures for implementing NEPA. The proposed NEPA implementing procedures are necessary to assist FirstNet in establishing an NEPA compliance program and applying the appropriate level of NEPA review for activities undertaken by FirstNet in the design, construction and operation of the nationwide interoperable PSBN. Accordingly, FirstNet is requesting public comment on its proposed implementing procedures before utilizing them as part of its NEPA review process. The proposed procedures are set forth as an addendum to this notice.

II. Background

FirstNet is responsible for, at a minimum, ensuring nationwide standards for the use of and access to the network; issuing open, transparent and competitive requests for proposals (RFPs) to build, operate and maintain the network; encouraging these RFPs to leverage, to the maximum extent economically desirable, existing commercial wireless infrastructure to speed deployment of the network; and overseeing contracts with non-federal entities to build, operate and maintain the network.

The specific actions anticipated to be undertaken by FirstNet encompass a variety of activities including the installation of cables, cell towers, antenna colocations, buildings, and power units as defined in the following examples:

(a) *Buried Plant/Facilities:* The construction of buried outside plant facilities generally consists of plowing or trenching cable at a depth of approximately 36″ to 48″ alongside the road usually in a utility corridor or within public road rights-of-way.

(b) *Aerial Plant/Facilities:* The construction of aerial facilities is either done by installing new poles and hanging cables on it on public rights-of-way or by installing cables using existing poles lines from a third party.

(c) *Towers:* The construction of towers for cell sites and/or microwave dishes. Tower construction is typically done by installing a concrete foundation and building the tower on it. The heights of the towers vary from 120 feet to 400 feet.

(d) *Co-Locations:* The mounting or installation of an antenna on an existing tower, building or structure for the purpose of transmitting and/or receiving radio frequency signal for communication purposes.

(e) *Building construction:* Generally consists of installing small pre-fabricated shelters on tower sites that are used for housing electronic equipment. These shelters are usually placed on concrete pads and generally require very minimal disturbance of the land. On extremely rare occasion, the construction of a headquarters and/or warehouse building may be necessary. The amount of land disturbance resulting from this type of construction can vary depending on the size of the proposed building.

(f) *Power Units:* The installation of power units, such as, an uninterruptible power supply (UPS) could be added to existing third party tower sites either on the existing concrete pad or by adding a new concrete pad if required at the site.

FirstNet is also required to leverage, to the maximum extent economically possible, existing commercial infrastructure in its deployment and operation of the PSBN.

The geographic scope of the PSBN encompasses all U.S. states and territories. Thus, FirstNet actions will likely occur in a wide range of environmental settings and require FirstNet to establish a process for analyzing proposed actions and making NEPA determinations based on the specific location and type of proposed project activities.

Therefore, FirstNet seeks to establish NEPA implementing procedures to better follow the letter and spirit of NEPA; comply fully with the CEQ Regulations; and apply the NEPA review process early in the planning stages of the PSBN.

III. Paperwork Reduction Act

The notice does not contain collection-of-information requirements subject to the Paperwork Reduction Act (PRA) of 1995 (44 U.S.C. 3501 *et seq.*). Notwithstanding any other provisions of law, no person is required to, nor shall a person be subject to penalty for failure to comply with, a collection of information subject to the requirements of PRA unless that collection of information displays a currently valid OMB control number.

IV. Environmental Impact

These NEPA procedures are intended to supplement CEQ regulations and provide guidance to FirstNet employees regarding the procedural requirements for the application of NEPA to FirstNet. CEQ does not direct agencies to prepare NEPA analysis or document before establishing agency procedures that supplement the CEQ regulations for implementing NEPA. Agency NEPA procedures are procedural guidance to assist agencies in the fulfillment of their responsibilities under NEPA. The requirements for establishing NEPA procedures are set for at 40 CFR 1505.1 and 1507.3.

Dated: December 30, 2013.

Stuart Kupinsky,

Chief Counsel, First Responder Network Authority.

Addendum

First Responder Network Authority Management Directive

First Responder Network Authority Procedures for Implementing the National Environmental Policy Act

Sections

1.01 Purpose
1.02 Scope
1.03 Policies
1.04 Definitions
1.05 Program Goals
1.06 Responsibilities
1.07 Environmental Review Process
1.08 Effective Date
Appendix A—List of Authorities
Appendix B—Glossary
Appendix C—Categorical Exclusions
Appendix D—Extraordinary Circumstances

1.01 Purpose

The purpose of this Management Directive (Directive) is to establish the First Responder Network Authority (FirstNet) policies, requirements, and procedures for complying with the National Environmental Policy Act, 42 U.S.C. 4321 *et seq.* (NEPA), and the implementing regulations issued by the Council on Environmental Quality (CEQ Regulations) as codified in Parts 1500–1508 of Title 40 of the Code of Federal Regulations (40 CFR Parts 1500–1508).

1.02 Scope

The provisions of this Directive apply to actions undertaken by FirstNet and specifically apply to any of the following actions undertaken by FirstNet:

(a) Legislative proposals initiated by FirstNet for which FirstNet would have primary action responsibility.

(b) Research, projects, and activities directly undertaken by FirstNet, or the research, projects and activities of a non-Federal entity supported or facilitated by FirstNet, including through grants and other forms of financial assistance, where FirstNet has sufficient involvement to influence, control, direct or affect material aspects of the research, project or activity.

(c) Actions to establish an official policy or adopt a formal plan or program. (40 CFR 1508.18).

1.03 Policies

FirstNet policies and programs shall be planned, developed, and implemented so as to achieve the goals and to follow the procedures declared by NEPA in order to assure responsible stewardship of the environment for present and future generations. Accordingly, FirstNet shall adhere to the following actions to ensure compliance with NEPA.

(a) FirstNet adopts the CEQ Regulations (40 CFR Parts 1500–1508) for implementing NEPA.

(b) FirstNet shall:

1. Comply with the CEQ Regulations (40 CFR Parts 1500–1508);

2. Report and coordinate its policies and procedures with the Department of Commerce Office of General Counsel, as appropriate;

3. Ensure activities and planning regarding Federal actions consider the environmental consequences of proposed actions in conjunction with mission requirements and objectives;

4. Consider and give weight to environmental factors in making decisions in order to achieve a proper balance between the development and utilization of natural, cultural and human resources, and the protection and enhancement of environmental quality;

5. Consult, coordinate and cooperate with other Federal agencies and, where appropriate, state, local and tribal governments in the development and implementation of FirstNet's plans and programs affecting environmental quality and, in turn, to give consideration to those activities that succeed in best addressing state and local concerns;

6. Identify potential Federal, state, local and tribal cooperating agencies early during the NEPA scoping process;

7. Participate as a lead or cooperative agency, as appropriate, with other federal agencies where FirstNet is involved in the same action as other agencies, or is involved in an action which is related to another agency's action because of their functional interdependence or geographical proximity;

8. As requested, and where resources allow, review and provide comments on draft NEPA documents submitted by other Federal agencies where the action relates to FirstNet's mission or operations;

(c) FirstNet shall ensure appropriate action is taken to comply with NEPA when actions are planned by private applicants or other non-Federal entities before Federal involvement so that:

1. Policies or designated staff is available to advise potential applicants of existing studies or other information foreseeably required for later Federal action.

2. The Federal agency consults early with appropriate state, local and tribal governments and with interested private persons and organizations when its own involvement is reasonable foreseeable.

3. The Federal agency commences its NEPA process at the earliest possible time.

(d) While it is the policy of FirstNet to fully evaluate its actions in accordance with the requirements of NEPA and the CEQ regulations, certain actions may result from statutory requirements involving little or no discretion on the part of FirstNet. In the case of such actions, a determination of non-applicability of NEPA should be made by the FirstNet NEPA Coordinator in coordination with the FirstNet Chief Counsel.

1.04 Definitions

This Directive incorporates all definitions and phrases as defined by CEQ in its regulations at 40 CFR Part 1508. To ensure full compliance, the CEQ regulations should be consulted for comprehensive explanations of the terms. A glossary of words and phrases as used in this Directive is included in Appendix B.

1.05 Program Goals

FirstNet will follow a systematic, interdisciplinary approach to planning in order to ensure a reasonable use of environment resources without degradation, risk to health and safety, or other undesirable and unintended consequences. The FirstNet NEPA program is designed to ensure that:

(a) Proposed actions to be undertaken by FirstNet are identified early in the planning process, and brought to the attention of the NEPA Coordinator;

(b) Actions are evaluated to determine the appropriate applicable NEPA review (i.e., CE, Environmental Assessment (EA), or Environmental Impact Study (EIS));

(c) An interdisciplinary approach is taken to proactively consider environmental impacts and identify and consider the full range of viable alternatives at the earliest planning stages of an action and prior to rendering any decision;

(d) The planning process integrates environmental review and consultation requirements;

(e) The impacts of proposed activities, programs, and projects on the quality of the human environment are considered before making an irretrievable and irreversible commitment of resources; and

(f) The public is engaged and involved with the planning process and evaluation of environmental impacts, as appropriate.

1.06 Responsibilities

FirstNet roles and responsibilities relating to the implementation and compliance with NEPA are as follows:

(a) The Chair of the Board (Chair). The Chair has the ultimate responsibility to fulfill FirstNet's compliance with NEPA. The Chair directs the FirstNet General Manger (GM) to (1) ensure that environmental planning is incorporated into FirstNet decision making processes and (2) coordinate with the designated NEPA Coordinator for advice and guidance on proper and adequate compliance with NEPA requirements.

(b) FirstNet General Manger (GM). The GM shall:

1. Establish and oversee the proper implementation of a FirstNet NEPA compliance program in accordance with the requirements of this Directive;

2. Advise the Chair on NEPA processes that are highly controversial, are nationally significant, or require the establishment of a new FirstNet NEPA-related policy;

3. Inform the Chair of current developments in NEPA policy and implementing procedures;

4. Support early, proactive, and comprehensive coordination and outreach processes across FirstNet;

5. Appoint a NEPA Coordinator to carry out the responsibilities delineated below in paragraph c; and

6. Sign Records of Decision (ROD), Findings of No Significant Impact (FONSIs) and memos citing Categorical Exclusions (CEs), or re-delegate this authority in writing to other FirstNet personnel, as appropriate.

(c) FirstNet NEPA Coordinator (NEPA Coordinator). Responsible for coordinating and overseeing FirstNet's compliance with NEPA. To accomplish this the NEPA Coordinator will:

1. Assist the Chair and GM in implementing FirstNet's compliance with NEPA;

2. Review and provide final clearance on all NEPA documents covered by this Directive;

3. Transmit, with written recommendation, all NEPA documents for action to the GM or authorized designee for signature or other appropriate agency action;

4. Develop and recommend policies, procedures and technical and administrative advice and training to facilitate and improve FirstNet's effective and efficient implementation of NEPA.

5. Provide technical and administrative advice and training to relevant stakeholders so that they are aware of, and comply with, the NEPA process and so that they consider the impacts of their programs, projects, and policies;

6. Act as liaison with the Department, CEQ and U.S. EPA on NEPA-related matters or issues, and coordinate with other federal agencies with respect to significant NEPA matters;

7. Prepare or review, as appropriate, all inter- or intra-agency reports, surveys and comments on NEPA-related matters, including other agency NEPA documentation, or legislative proposals;

8. Consult early and often with relevant stakeholders to identify how the requirements of this Directive will be met. At a minimum:

A. Determine the applicability of NEPA and, if applicable, the appropriate NEPA review procedure (i.e., CE, EA, or EIS) and public involvement, in consultation with the Chief Counsel of FirstNet, as necessary;

B. Review and comment upon draft NEPA documents to ensure that a high-quality analysis is completed, reasonable or appropriate alternatives are identified and discussed, and that all applicable scheduling, scoping, consultation, circulation, and public involvement requirements are met;

C. Assist in consultations with other Federal, state, and local regulatory and/or resource agencies and tribal governments on draft NEPA documents, as appropriate; and

D. Otherwise act as a resource to the relevant stakeholders to ensure that the NEPA document to be prepared identifies reasonably foreseeable significant impacts of the action, sufficiently analyzes the impacts, clearly presents the findings and fairly considers reasonable or appropriate alternatives to the action.

(d) FirstNet Chief Counsel: The Chief Counsel of FirstNet shall provide all legal services regarding NEPA compliance, including:

1. Providing legal sufficiency reviews of NEPA documents, as appropriate;

2. Assisting the Chair, GM, and NEPA Coordinator in determining the applicable NEPA review for a proposed action; and

3. Assisting the Chair, GM, and NEPA Coordinator in establishing or revising this Directive and the FirstNet NEPA compliance program, as necessary.

1.07 Environmental Review Process

The environmental review process describes the applicable CE, EA, or EIS process for a proposed FirstNet action and includes actions required by CEQ in 40 CFR parts 1500–1508 for compliance with NEPA. The process involves the following series of actions accomplished by or under the direction of the Chair of FirstNet or a delegate.

Developing the Purpose and Need

FirstNet shall ensure the purpose and need of a proposed action considers the FirstNet mission. FirstNet is authorized and directed by statute to take all actions necessary to ensure the design, construction, and operation of a nationwide interoperable public safety broadband network (PSBN) based on a single, national network architecture. The establishment of the nationwide PSBN meets a long-standing and critical national infrastructure need that will, for the first time, allow police officers, fire fighters, emergency medical service professionals, and other public safety officials to effectively communicate with each other across agencies and jurisdictions.

Apply NEPA Early in the Process

FirstNet shall integrate the NEPA process with other planning for the nationwide PSBN at the earliest possible time to ensure that planning and decisions reflect environmental values to avoid delays later in the process and head off potential conflicts. Accordingly, FirstNet shall:

(a) Identify environmental impacts and resources in adequate detail so they can be compared and evaluated with economic and technical considerations. Wherever practicable, environmental documents with appropriate analyses should be circulated and reviewed at the same time as other planning documents.

(b) Study, develop, and analyze reasonable alternatives to recommended courses of action. Consider mitigation measures which could avoid, ameliorate, lessen, or compensate identified impacts of the proposed action.

(c) Where the action requiring FirstNet review is by a private applicant or other non-Federal entity:

1. The NEPA Coordinator or an assigned FirstNet Environmental Protection Specialist will advise the applicant of FirstNet's policies and procedures for NEPA compliance, and make available or direct the applicant to resources within FirstNet, the Department or elsewhere in the Federal government to facilitate the applicant's consideration of and explanation of environmental impacts and alternatives.

2. FirstNet will consult with appropriate state, local, and tribal governments and appropriate organizations on environmental impacts and alternatives of the proposed action when its own involvement is reasonably foreseeable.

3. FirstNet will initiate its NEPA review process at the earliest practicable time.

Scoping

FirstNet shall comply with scoping procedures described in 40 CFR 1501.7 required for proposed actions normally requiring an EA with scoping or an EIS. FirstNet may also require scoping procedures to be followed for other proposed actions where appropriate to achieve the purposes of NEPA. When evaluating the type and extent of the NEPA documents and review appropriate for a proposed action, FirstNet shall:

(a) Define the purpose and need of the proposed action;

(b) Identify reasonably foreseeable impacts of the action to determine if consultation with other federal, state, local or tribal entities is needed;

(c) Determine if other federal agency action is involved in the proposed action so lead and coordinating agencies can be established;

(d) Identify or develop reasonable alternatives to the proposed action;

(e) Consider the context and intensity of the potential direct, indirect, and cumulative environmental effects of the proposed action(s) and any reasonable or appropriate alternatives;

(f) Consider mitigation measures or strategies to minimize, reduce, or eliminate environmental impacts of the proposed action(s), as necessary;

Public Involvement

In carrying out its responsibilities under NEPA, FirstNet shall comply with the public involvement requirements described in 40 CFR 1506.6 and make diligent efforts to involve the public in the environmental review process. In addition, FirstNet shall:

(a) Ensure that all public notices relating to environmental matters shall describe the nature, location, and extent of the proposed action and indicate the availability and location of additional information relating to the matter.

(b) Determine the appropriate medium for publishing notices relating to environmental matters on a project-by-project basis.

(c) Assess and consider public comments both individually and collectively and ensure that responses to public comments are appended to the applicable environmental document, as appropriate.

(d) Make available to the public those project-related environmental documents that FirstNet determines will enhance public participation in the environmental process. These materials shall be placed in locations convenient for the public as determined by FirstNet.

(e) Hold public hearings or meetings at reasonable times and locations concerning environmental aspects of a proposed action in all cases where, in the opinion of FirstNet, the need for hearings or meetings is indicated in order to develop adequate information on the environmental implications of the proposed action. Public hearings or meetings conducted by FirstNet will be coordinated to the extent practicable with other meetings, hearings, and environmental reviews which may be held or required by other Federal, state and local agencies.

General Requirements for Categorical Exclusions

FirstNet actions that do not individually or cumulatively have a significant effect on the human environment and where no extraordinary circumstances exist may be categorically excluded from further environmental review in an EA or EIS.

(a) The approved list of FirstNet actions that normally qualify for a CE are listed in Appendix C.

(b) FirstNet actions that would normally be categorically excluded from further environmental review but due to the existence of extraordinary circumstances could have substantial environmental effects will require the preparation of an EA or EIS.

(c) This list of extraordinary circumstances that could have substantial environmental effects is listed in Appendix D.

(d) If a proposed action is determined to be a CE and not considered a routine administrative, personnel action, or procurement, FirstNet shall document its determination that a CE applies to a proposed action with a Record of Environmental Consideration.

(e) The list of approved FirstNet CE's is subject to continual review and can be modified by amending/revising this Directive, in consultation with CEQ.

(f) The use of a CE does not relieve FirstNet from compliance with other statutes or consultations under the Endangered Species Act of 1973 (16 U.S.C. 1531 *et seq.*) or the National Historic Preservation Act of 1966 (16 U.S.C. 470 *et seq.*). Such consultations may be required to determine the applicability of the CE screening criteria

General Requirements for an Environmental Assessment

FirstNet shall prepare an EA as defined in 40 CFR 1508.9 for an action which FirstNet determines may have the potential for significant environmental impact. Actions normally requiring an EA include:

(a) When a proposed action is not in a category of actions described in an available categorical exclusion and there is not enough information available to know that the proposed action will have significant environmental impacts, an EA will be prepared. In this situation, an EA process is used to determine, through environmental impact evaluation and opportunity for public involvement, if the impacts on the quality of the human environment are potentially significant.

(b) A proposed action that is included in a category of actions described in a categorical exclusion, but extraordinary circumstances may present the potential for significant environmental impacts precluding the categorical exclusion, and there is a the lack of information to determine that the proposed action will have significant environmental impacts requiring preparation of an EA.

(c) The Chair or a delegate can decide to prepare an EA as a best practice planning tool to inform decision makers on the environmental impacts of its actions.

In preparing an EA, First shall:

(a) Involve environmental agencies, applicants, and the public to the extent practicable.

(b) Ensure the contents of an EA comply with the requirements of 40 CFR 1508.9, and, at minimum, shall include:

1. Sufficient evidence and analysis for FirstNet to determine whether to prepare an EIS or a FONSI, and facilitate preparation of said EIS, if needed;

2. A brief discussion of the need for the action;

3. A brief discussion of the environmental impacts of the proposed action and alternatives; and

4. A listing of agencies and person consulted

(c) Determine, based on an independent review of the EA, whether the proposed action will have a significant environmental impact. If FirstNet determines that the proposed action will not have a significant impact, FirstNet may issue a FONSI as described in 40 CFR 1508.13. However, if, after review of the EA, FirstNet determines that the proposed action will have a significant environmental impact, FirstNet will proceed with the preparation of an EIS.

General Requirements for and Environmental Impact Statement

FirstNet shall prepare an EIS when it determines that a proposed action significantly impacts the quality of the human environment or when the results of an EA indicate the proposed action will have significant impacts. Actions normally requiring the preparation of an EIS include:

(a) Major federal actions found to cause significant effects on the human

environment which cannot be mitigated to a level of insignificance (identifiable at the start of the NEPA process or through the preparation of an EA).

(b) Major federal actions occurring in the U.S. known to cause significant environmental effects on the global commons, such as the oceans or Antarctica, as described in EO 12114, Environmental Affects Abroad of Major Federal Actions.

(c) Actions required by statute or treaty to develop an EIS.

In preparing and EIS, FirstNet shall solicit public involvement and commenting as described in 40 CFR 1503.1–1503.4 after preparing a draft EIS and before preparing a final EIS. FirstNet shall also ensure the contents of an EIS contain the elements described in 40 CFR 1502.10–1502.18 and, unless FirstNet determines that there is a compelling reason to do otherwise shall follow the standard EIS format and include:

1. Cover Sheet
   i. See 40 CFR 1502.11
2. Summary
   i. See 40 CFR 1502.12
3. Table of Contents
4. Purpose of and Need for Action
   i. See 40 CFR 1502.13
5. Discussion of Proposed Action and Alternatives
   i. See 40 CFR 1502.14
6. Description of the Affected Environment
   i. See 40 CFR 1502.15
7. Discussion of the Environmental Consequences of the Proposed Action
8. See 40 CFR 1502.16
9. List of Preparers
   i. See 40 CFR 1502.17
10. List of Agencies, Organizations, and Persons Consulted
11. Index and Appendices, as appropriate

Finally, FirstNet shall prepare a concise public Record of Decision (ROD) in accordance with 40 CFR 1505.2.

Environmental Review and Consultation Requirements for NEPA Reviews

To the fullest extent possible, FirstNet shall prepare NEPA reviews (i.e., CE, EA, EIS) concurrently with and integrated with environmental analyses and related surveys and studies required by the Fish and Wildlife Coordination Act (16 U.S.C. 661 *et seq.*), National Historic Preservation Act of 1966 (16 U.S.C. 470 *et seq.,* Endangered Species Act of 1973 (16 U.S.C. 1531 *et seq.*), E.O. No. 11990, Protection of Wetlands, and E.O. No. 11988, Floodplain Management, and other environmental review laws and executive orders.

Cumulative Impacts

FirstNet NEPA analyses shall assess cumulative effects, which are the impacts on the environment resulting from the incremental impact of the action when added to other past, present, and reasonable foreseeable future actions (40 CFR 1508.7).

Environmental Justice

FirstNet shall comply with Executive Order 12898, ''Federal Actions to Address Environmental Justice in Minority and Low-Income Populations,'' and determine whether the proposed action will have a disproportionate impact on minority or low-income communities.

Environmental Determinations and Final Decisions

The conclusion of the NEPA review process will result in one of the following environmental determinations or final decisions.

(a) Record of Environmental Consideration

1. If a proposed action is determined to be a CE and not considered a routine administrative or personnel action, FirstNet shall document its determination that a CE applies to a proposed action with a memorandum to the file.

2. A Record of Environmental Consideration is a brief memorandum that is kept in the administrative record and should cite the categorical exclusion used and show that the agency determined: (1) The action fits within the category of actions described in the categorical exclusions; and (2) there are no extraordinary circumstances that would preclude the project or proposed action from qualifying as a categorically excluded action.

(b) Finding of No Significant Impact (FONSI)

1. An EA results in either the issuance of FONSI or a determination to prepare an EIS. A FONSI is a document (40 CFR 1508.13) that briefly states why an action (not otherwise excluded) will not significantly affect the environment.

2. If the Chair or delegate determines, based on an independent review of the EA, that the proposed action will not have significant impact, FirstNet may issue a FONSI and proceed with the proposed action. However, if, after an independent review of the EA, it is determined by the Chair or a delegate that the proposed action will have a significant environmental impact, FirstNet will proceed with the preparation of an EIS.

(c) Record of Decision (ROD)

1. When it is determined that an EIS is required, FirstNet's final decision relating to the proposed action will consider the environmental information provided in the EIS and require the preparation of an ROD. The ROD documents the final decision made and the basis for that decision. An ROD shall be prepared in accordance with 40 CFR 1505.2 for the final decision maker, whether the Chair or a delegate, for approval and signature.

2. FirstNet's implementation of the proposed action may begin immediately after approval of the ROD.

Mitigation

FirstNet, throughout the environmental review process, shall consider mitigation measures, as defined in 40 CFR 1508.20, to avoid or minimize environmental harm, where possible. In addition, the following actions will be taken to ensure proper implementation of mitigation measures:

(a) FirstNet shall ensure a discussion of mitigation measures essential to render the impacts of the proposed action not significant be included in or referenced in the FONSI and the ROD prior to making a final environmental determination or decision relating the significant of the impacts.

(b) FirstNet will not commit to mitigation measures considered or analyzed in environmental documentation if there are insufficient legal authorities, or it is not reasonable to foresee the availability of sufficient resources to perform or ensure the performance of the mitigation.

(c) Prior to and during the implementation of the action, FirstNet shall monitor project activities to ensure the proper execution of any mitigation measures or other conditions established and committed to in environmental documentation, as appropriate.

(d) If mitigation commitments made in NEPA and decision documents fail to achieve projected environmental outcomes and there is remaining federal action, FirstNet may utilize an adaptive management approach and take corrective actions to identify alternatives that could take the place of original mitigation commitments and provided the intended environmental result.

Tiering

FirstNet shall tier environmental documents to eliminate repetitive discussions of the same issues and to focus on the actual issues ripe for decision at each level of environmental

review, as appropriate (*see* 40 CFR 1508.28). When a broad EIS has been prepared, FirstNet need only summarize the issues discussed in the broader environmental document, incorporate discussions from the broader environmental document by reference, and therefore concentrate on issues specific to the subsequent action.

Supplemental Environmental Documentation

FirstNet may prepare supplements to either the draft or final environmental documentation if:

(a) FirstNet makes substantial changes in the proposed action that are relevant to environmental concerns; or

(b) There are significant new circumstances or information relevant to environmental concerns and bearing on the proposed action or its impacts.

(c) FirstNet is relying upon an environmental review previously performed by another federal agency, with authority over the action or related activity of an applicant and (I) additional analysis is needed to address the reasonably foreseeable impacts of the action under consideration by FirstNet or (II) it adequately addresses the reasonably foreseeable impacts of the action under consideration by FirstNet.

Emergencies

FirstNet may implement an emergency NEPA process after determining there is a need for taking action that does not allow for time for the regular NEPA process and complying with NEPA. This section applies only if the NEPA Coordinator, in consultation with FirstNet General Counsel, determines that an emergency exists that makes it necessary to take urgently needed actions before preparing a NEPA analysis and documentation in accordance with the provisions in subparts D and E of this part.

(a) The NEPA Coordinator may take those actions necessary to control the immediate impacts of the emergency that are urgently needed to mitigate imminent harm to life, property, or important natural, cultural, or historic resources. When taking such actions, the Responsible Official shall take into account the probable environmental consequences of these actions and mitigate foreseeable adverse environmental effects to the extent practical.

(b) The NEPA Coordinator or designee shall document in writing the determination that an emergency exists and describe the responsive action(s) taken at the time the emergency exists. The form of that documentation is within the discretion of the Responsible Official.

(c) If the NEPA Coordinator determines that proposed actions taken in response to an emergency, beyond actions noted in paragraph (a) of this section, are not likely to have significant environmental impacts, the NEPA Coordinator or designee shall document that determination in an environmental assessment and a FONSI prepared in accordance with this part, unless categorically excluded. If the NEPA Coordinator finds that the nature and scope of the subsequent actions related to the emergency require taking such proposed actions prior to completing an EA and a FONSI, the NEPA Coordinator shall consult with the General Counsel about alternative arrangements for NEPA compliance. The NEPA Coordinator or designee may grant an alternative arrangement. Any alternative arrangement must be documented and notice of its use provided to CEQ.

(d) The NEPA Coordinator shall consult with CEQ about alternative arrangements as soon as possible if the Responsible Official determines that proposed actions taken in response to an emergency are likely to have significant environmental impacts. Such alternative arrangements will apply only to the proposed actions necessary to control the immediate impacts of the emergency. Other proposed actions remain subject to NEPA analysis and documentation in accordance with this part.

1.08 Effective Date

The effective date for the FirstNet NEPA implementation procedures is to be determined after the comment period.

Appendix A

List of Authorities

(a) Statutes and Regulations that should be considered during the development of a NEPA review should include, but not be limited to:

1. National Environmental Policy Act (NEPA) of 1969, 42 U.S.C. 4321 *et seq.*
2. CEQ Regulations for Implementing the Procedural Provisions of the National Environmental Policy Act, as codified at 40 CFR Parts 1500—1508.
3. Endangered Species Act of 1973, 16 U.S.C. 1531 *et seq.*
4. Fish and Wildlife Coordination Act, 16 U.S.C. 661 *et seq.*
5. National Historic Preservation Act of 1966, 16 U.S.C. 470 *et seq.*
6. Migratory Bird Treaty Act of 1918, 16 U.S.C. 703 *et seq.*
7. Clean Air Act of 1970, 42 U.S.C. 7401 *et seq.*
8. Clean Water Act, 33 U.S.C. 1251 *et seq.*
9. Coastal Zone Management Act of 1972, 16 U.S.C. 1451 *et seq.*
10. Wild and Scenic Rivers Act of 1968, 16 U.S.C. 1271 *et seq.*
11. Marine Mammal Protection Act of 1972, 16 U.S.C. 31 *et seq.*
12. River and Harbors Act of 1899, 33 U.S.C. 401 and 403.

(b) Executive Orders that should be considered during the development of a NEPA review should include, but not be limited to:

1. E.O. No. 11988, Floodplain Management.
2. E.O. No. 12114, Environmental Effects Abroad of Major Federal Actions.
3. E.O. No. 11990, Protection of Wetlands.
4. E.O. No. 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations.
5. E.O. No. 13112, Invasive Species.
6. E.O. No. 13175, Consultation and Coordination with Indian Tribal Governments.
7. E.O. No. 13186, Responsibilities of Federal Agencies to Protect Migratory Birds.

(c) CEQ Guidance Documents that should be considered during the development of a NEPA review should include, but not be limited to:

1. ''Memorandum for Heads of Federal Departments and Agencies: Improving the Process for Preparing Efficient and Timely Environmental Reviews Under the National Environmental Policy Act'' (CEQ, 2012).
2. ''Memorandum for Heads of Federal Departments and Agencies: Appropriate Use of Mitigation and Monitoring and Clarifying the Appropriate Use of Mitigated Findings of No Significant Impact'' (CEQ, 2011).
3. ''Memorandum for Heads of Federal Departments and Agencies: Establishing, Applying, and Revising Categorical Exclusions Under the National Environmental Policy Act'' (CEQ, 2010).
4. ''Memorandum for Heads of Federal Departments and Agencies: Emergencies and the National Environmental Policy Act'' (CEQ, 2010).
5. ''Aligning National Environmental Policy Act Processes with Environmental Management Systems'' (CEQ/NEPA Task Force, 2007).
6. ''Collaboration in NEPA: A Handbook for NEPA Practitioners'' (CEQ/NEPA Task Force, 2007).
7. ''Memorandum for Federal NEPA Contacts: Emergency Actions and NEPA'' (CEQ, 2005).
8. ''Memorandum for Federal NEPA Contacts: Emergency Actions and NEPA, Appendix 2: Preparing Focused, Concise and Timely Environmental Assessments'' (CEQ, 2005).
9. ''Guidance on the Consideration of Past Actions in Cumulative Effects Analysis'' (CEQ, 2005).
10. ''Modernizing NEPA Implementation'' (CEQ/NEPA Task Force, 2003).
11. ''CEQ Memorandum for Deputy/Assistant Heads of Federal Agencies: Identifying Non-Federal Cooperating Agencies in Implementing the Procedural Requirements of the National Environmental Policy Act'' (CEQ, 2000).
12. ''CEQ Memorandum for Heads of Federal Agencies: Designation of Non-

Federal Agencies to be Cooperating Agencies in Implementing the Procedural Requirements of NEPA'' (CEQ, 1999).

13. ''Considering Cumulative Effects Under the National Environmental Policy Act'' (CEQ, 1997).

14. ''Environmental Justice: Guidance Under the National Environmental Policy Act'' (CEQ, 1997).

15. ''CEQ Guidance on NEPA Analyses for Transboundary Impacts'' (CEQ, 1997).

16. ''Memorandum to Heads of Federal Departments and Agencies Regarding Pollution Prevention and the National Environmental Policy Act'' (CEQ, 1993).

17. ''Incorporating Biodiversity Considerations into Environmental Impact Analysis Under the National Environmental Policy Act'' (CEQ, 1993).

18. ''CEQ Guidance Regarding NEPA Regulations'' (CEQ, 1983).

19. ''Forty Most Asked Questions Concerning CEQ's NEPA Regulations'' (CEQ, 1981).

20. ''Guidance on Applying Section 404(r) of the Clean Water Act to Federal Projects Which Involve the Discharge of Dredged or Fill Materials into Waters of the U.S., Including Wetlands'' (CEQ, 1980).

21. ''Environmental Effects Abroad of Major Federal Actions, Executive Order 12114; Implementing and Explanatory Documents'' (CEQ, 1979).

22. ''CEQ Memorandum for Heads of Agencies: Implementation of Executive Order 11988 on Floodplain Management and Executive Order 11990 on Protection of Wetlands'' (CEQ, 1978).

23. ''Environmental Review Pursuant to Section 1424(e) of the Safe Drinking Water Act of 1974 and its Relationship to NEPA'' (CEQ, 1976).

Appendix B

Glossary

All terminology and definitions contained in 40 CFR Parts 1500–1508 are incorporated into this Directive. The following definitions are provided for other terms and phrases used.

(a) *Applicant.* Any party who may apply to FirstNet for a Federal permit, funding, or other approval or any party proposing such an action. Any application should be accompanied by an explanation of the expected or reasonably foreseeable environmental impacts, identify, as appropriate, alternatives to the action and provide supporting documentation. Depending on the program, the applicant can be an individual, a private organization, or a Federal, state, tribal, or territorial government body.

(b) *Chair of the Board.* Member of the FirstNet Board selected by the Secretary of Commerce to serve Chair of the Board for FirstNet.

(c) *Council on Environmental Quality (CEQ).* Organization with the Executive Office of the President charged with monitoring progress toward achieving the national environmental goals as set forth in NEPA. The CEQ promulgates regulations governing the NEPA process for all Federal agencies.

(d) *Environmental Impact Statement (EIS).* A detailed written statement prepared by an agency if a proposed action significantly impacts the quality of the human environment. The decision to prepare an EIS is based on the Agency's determination that the potential impacts are significant or the results of an EA indicate significant impacts. An EIS should include discussions of the purpose of and need for the action, alternatives, the affected environment, the environmental consequences of the proposed action, lists of preparers, agencies involved, response to any public comments received, organizations and persons to whom the statement is sent, an index, and an appendix (if any). An EIS is prepared in two stages: a draft and a final. Either stage of an EIS may be supplemented.

(e) *Environmental Review.* This term refers to the NEPA process which includes: (1) identifying and scoping issues related to the proposed action; (2) determining the necessary steps for NEPA compliance and preparing the NEPA review (CE, EA, or EIS); and (3) making decisions that are based on understanding the environmental consequences of the proposed action.

(f) *Finding of No Significant Impact (FONSI).* A short NEPA document that presents the reasons why an action will not have a significant impact on the quality of the human environment and, therefore, will not require the preparation of an EIS. A FONSI must be supported by an EA, and must include, summarize, attach or incorporate by reference the EA. (40 CFR 1508.13).

(g) *FirstNet General Manager.* Individual responsible for implementing the policies and strategies approved by the FirstNet Board, and overseeing all of the day-to-day operations of FirstNet.

(h) *Mitigation.* Measures taken to allow the proposed action to: avoid environmental impacts altogether; minimize impacts by limiting the degree or magnitude of the action; rectify the impact by repairing, rehabilitating, or restoring the affected environment; reduce or eliminate the impact over time by preservation; and/or compensate for the impact.

(i) *NEPA Coordinator.* Individual responsible for coordinating and overseeing FirstNet's compliance with NEPA.

(j) *NEPA Document.* An EA, FONSI, draft, supplemental draft, or final EIS, Record of Decision (ROD), or memorandum documenting the application of CE.

(k) *Project.* A Federal action such as a grant, contract, loan, loan guarantee, vessel capacity reduction program, land acquisition, construction project, license, permit, modification, regulation, or research program that involves FirstNet's review, approval, implementation, or other administrative action.

(l) *Record of Decision (ROD).* A pubic document signed by the agency decision maker following the completion of an EIS. The ROD states the decision, alternatives considered, the environmentally preferable alternative(s), factors considered in the agency decision, mitigation measures that will be implemented, and whether the practicable means to avoid or minimize environmental harm have been adopted (40 CFR 1505.2).

(m) *Supplemental Environmental Documents.* A document prepared to amend an original NEPA document when there is a significant change in the action proposed beyond the scope of the original environmental review or when circumstances or information arise that could affect the proposed action and its environmental impacts (40 CFR 1502.9(c)).

Appendix C

Categorical Exclusions

A.1: The issuance of bulletins and information publications that do not concern environmental matters or substantial facility design, construction, or maintenance practices.

A.2: Procurement activities related to the operation of FirstNet.

A.3: Personnel and Administrative Actions.

A.4: Purchase of existing facilities or a portion thereof where use or operation will remain unchanged.

A.5: Internal modifications or equipment additions (*e.g.,* computer facilities, relocating interior walls) to structures or buildings.

A.6: Construction of buried and aerial telecommunications lines, cables, and related facilities.

A.7: Construction of microwave facilities involving no more than five acres (2 hectares) of physical disturbance at any single site.

A.8: Construction of cooperative or company headquarters, maintenance facilities, or other buildings involving no more than 10 acres (4 hectares) of physical disturbance or fenced property.

A.9: Changes to existing transmission lines that involve less than 20 percent pole replacement, or the complete rebuilding of existing distribution lines within the same right of way. Changes to existing transmission lines that require 20 percent or greater pole replacement will be considered the same as new construction.

A.10: Changes or additions to existing substations, switching stations, telecommunications switching or multiplexing centers, or external changes to buildings or small structures requiring one acre (0.4 hectare) or more but no more than five acres (2 hectares) of new physically disturbed land or fenced property.

A.11: Construction of substations, switching stations, or telecommunications switching or multiplexing centers requiring no more than five acres (2 hectares) of new physically disturbed land or fenced property.

A.12: Changes or additions to microwave sites, substations, switching stations, telecommunications switching or multiplexing centers, buildings, or small structures requiring new physical disturbance or fencing of less than one acre (0.4 hectare).

A.13: Ordinary maintenance or replacement of equipment or small structures (*e.g.,* line support structures, line transformers, microwave facilities, telecommunications remote switching and multiplexing sites).

A.14: The construction of telecommunications facilities within the

fenced area of an existing substation, switching station, or within the boundaries of an existing electric generating facility site.

A.15: Testing or monitoring work (*e.g.,* soil or rock core sampling, monitoring wells, air monitoring).

A.16: Studies and engineering undertaken to define proposed actions or alternatives sufficiently so that environmental effects can be assessed.

A.17: Rebuilding of power lines or telecommunications cables where road or highway reconstruction requires the applicant to relocate the lines either within or adjacent to the new road or highway easement or right-of-way.

A.18: Phase or voltage conversions, reconductoring or upgrading of existing electric distribution lines, or telecommunication facilities.

A.19: Construction of standby diesel electric generators (one megawatt or less total capacity) and associated facilities, for the primary purpose of providing emergency power, at an existing applicant headquarters or district office, telecommunications switching or multiplexing site, or at an industrial, commercial, or agricultural facility served by the applicant.

Appendix D

Extraordinary Circumstances

Extraordinary circumstances that preclude the use of a CE include:

(a) Reasonable likelihood of significant impact on public health or safety.

(b) Reasonable likelihood of significant environmental effects (direct, indirect, and cumulative).

(c) Reasonable likelihood of effects on the environment that are highly uncertain, unique, or are scientifically controversial.

(d) Reasonable likelihood of violating any federal, state, or local law or requirements imposed for the protection of the environment.

(e) Reasonable likelihood of adversely affecting ''environmentally sensitive'' resources, unless the impact has been resolved through another environmental process (*e.g.,* CZMA, NHPA, CWA).

Environmentally sensitive resources include:

1. Proposed federally listed, threatened, or endangered species or their designated critical habitat.

2. Properties listed or eligible for listing on the National Register of Historic Places.

3. Areas having special designation or recognition such as prime or unique or agricultural lands; designated wilderness or wilderness study areas; wild and scenic rivers; National Historic Landmarks (designated by the Secretary of the Interior); 100-year floodplains; wetlands; sole source aquifers (potential sources of drinking water); National Wildlife Refuges; National Parks; areas of critical environmental concern; or other areas of high environmental sensitivity.

(f) Reasonable likelihood of adversely impacting water quality, sole source aquifers, public water supply systems or state, local, or tribal water quality standards established under the Clean Water Act and the Safe Drinking Water Act.

(g) Reasonable likelihood of effects on the quality of the environment that is highly controversial on environmental grounds. The term ''controversial'' means a substantial dispute exists as to the size, nature, or effect of the proposed action rather than to the existence of opposition to a proposed action, the effect of which is relatively undisputed.

(h) Reasonable likelihood of a disproportionately high and adverse effect on low income or minority populations (*see* E.O. No. 12898).

(i) Limited access to and ceremonial use of Indian sacred sites on Federal lands by Indian religious practitioners or significantly adversely affect the physical integrity of such sacred sites.

(j) A greater scope or size than is normal for this category of action.

(k) Reasonable likelihood of degrading already existing poor environmental conditions. Also, initiation of a degrading influence, activity, or effect in areas not already significantly modified from their natural condition.

(l) Introduction or employment of unproven technology.

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DEPARTMENT OF DEFENSE

Office of the Secretary

[Docket ID: DoD–2014–HA–0001]

Proposed Collection; Comment Request

AGENCY: Office of the Assistant Secretary of Defense for Health Affairs, DoD.

ACTION: Notice.

SUMMARY: In compliance with Section 3506(c)(2)(A) of the *Paperwork Reduction Act of 1995,* the Office of the Assistant Secretary of Defense for Health Affairs announces a proposed public information collection and seeks public comment on the provisions thereof. Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the proposed information collection; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden of the information collection on respondents, including through the use of automated collection techniques or other forms of information technology.

DATES: Consideration will be given to all comments received by March 10, 2014.

ADDRESSES: You may submit comments, identified by docket number and title, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Mail:* Federal Docket Management System Office, 4800 Mark Center Drive, 2nd floor, East Tower, Suite 02G09, Alexandria, VA 22350–3100.

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

FOR FURTHER INFORMATION CONTACT: To request more information on this proposed information collection or to obtain a copy of the proposal and associated collection instruments, please write to Naval Health Research Center, DoD Center for Deployment Health Research, Department 164, ATTN: Martin White, MPH, 140 Sylvester Rd., San Diego, CA 92106–3521, or call (619) 553–9292.

SUPPLEMENTARY INFORMATION:

Title; Associated Form; and OMB Number: Prospective Department of Defense Studies of US Military Forces: The Millennium Cohort Study; OMB Control Number 0720–0029.

Needs and Uses: The Millennium Cohort Study responds to recent recommendations by Congress and by the Institute of Medicine to perform investigations that systematically collect population-based demographic and health data so as to track and evaluate the health of military personnel throughout the course of their careers and after leaving military service. The Millennium Cohort Study will also evaluate family impact by adding a spouse assessment component to the Cohort, called the Millennium Cohort Family Study.

Affected Public: Civilians, formerly Active Duty and activated Reservists in the US Military, who enrolled and participated in Panels 1, 2, 3, and 4 of the Millennium Cohort Study, and civilians who elect to participate in the Millennium Cohort Family Study.

Millennium Cohort Study

Annual Burden Hours: 35,060.

Number of Respondents: 46,747.

Responses per Respondent: 1.

Average Burden per Response: 45 minutes.

Frequency: every 3 years.

Millennium Cohort Family Study

Annual Burden Hours: 2,682.
Number of Respondents: 3,576.
Responses per Respondent: 1.
Average Burden per Response: 45 minutes.
Frequency: every 3 years.

Persons eligible to respond to this survey are those civilians now separated from military service who initially enrolled, gave consent, and participated in the Millennium Cohort Study while on active duty in the Army, Navy, Air Force, Marine Corps or US Coast Guard during the first, second, third, or fourth panel enrollment periods in 2001–2003, 2004–2006, 2007–2008, or 2011–2012 respectively, as well as civilians that choose to participate in the Millennium Cohort Family Study.

Dated: January 2, 2014.

Aaron Siegel,

Alternate OSD Federal Register Liaison Officer, Department of Defense.

[FR Doc. 2014–00061 Filed 1–7–14; 8:45 am]

BILLING CODE 5001–06–P

DEPARTMENT OF EDUCATION

List of Correspondence From January 1, 2013, Through March 31, 2013

AGENCY: Office of Special Education and Rehabilitative Services; Department of Education.

ACTION: Notice.

SUMMARY: The Secretary is publishing the following list of correspondence from the U.S. Department of Education (Department) to individuals during the previous quarter. The correspondence describes the Department's interpretations of the Individuals with Disabilities Education Act (IDEA) or the regulations that implement the IDEA. This list and the letters or other documents described in this list, with personally identifiable information redacted, as appropriate, can be found at: *http://www2.ed.gov/policy/speced/guid/idea/index.html*.

FOR FURTHER INFORMATION CONTACT: Jessica Spataro or Mary Louise Dirrigl. Telephone: (202) 245–7605.

If you use a telecommunications device for the deaf (TDD) or a text telephone (TTY), you can call the Federal Relay Service (FRS), toll free, at 1–800–877–8339.

Individuals with disabilities can obtain a copy of this list and the letters or other documents described in this list in an accessible format (e.g., braille, large print, audiotape, or compact disc) by contacting Jessica Spataro or Mary Louise Dirrigl at (202) 245–7605.

SUPPLEMENTARY INFORMATION: The following list identifies correspondence from the Department issued from January 1, 2013, through March 31, 2013. Under section 607(f) of the IDEA, the Secretary is required to publish this list quarterly in the **Federal Register**. The list includes those letters that contain interpretations of the requirements of the IDEA and its implementing regulations, and it may also include letters and other documents that the Department believes will assist the public in understanding the requirements of the law. The list identifies the date and topic of each letter, and it provides summary information, as appropriate. To protect the privacy interests of the individual or individuals involved, personally identifiable information has been redacted, as appropriate.

Part B—Assistance for Education of All Children With Disabilities

Section 612—State Eligibility

Topic Addressed: Children in Private Schools

○ Letter dated February 4, 2013, to New Jersey Catholic Conference Education Director George Corwell, regarding children with disabilities from other countries who are enrolled in private schools by their parents.

Section 613—Local Educational Agency Eligibility

Topic Addressed: Use of Federal Funds

○ Letter dated January 30, 2013, to Minnesota Department of Education Funding and Data Manager Carol Hokenson, regarding coordinated early intervening services and local educational agency (LEA) maintenance of effort requirements in Part B of the IDEA.

○ Letter dated March 7, 2013, to Wisconsin Department of Public Instruction Assistant Director of Special Education Troy Couillard, regarding the circumstances under which an LEA may use Part B funds for services for nondisabled children.

Section 615—Procedural Safeguards

Topic Addressed: Surrogate Parents

○ Letter dated March 27, 2013, to North Carolina attorney K. Dean Shatley, regarding court-appointed surrogate parents.

Topic Addressed: Due Process Complaint

○ Letter dated March 27, 2013, to New York attorney William J. Casey, regarding the purpose of resolution sessions.

Other Letters That Do Not Interpret IDEA but May Be Of Interest to Readers

○ Letter dated March 27, 2013, to District of Columbia Office of the State Superintendent of Education Assistant Superintendent Amy Maisterra, regarding the requirements in Part B of the IDEA that apply to children with disabilities educated at the Laurent Clerc National Deaf Education Center, as specified in the Education of the Deaf Act of 1986, as amended.

Electronic Access to This Document: The official version of this document is the document published in the **Federal Register**. Free Internet access to the official edition of the **Federal Register** and the Code of Federal Regulations is available via the Federal Digital System at: *www.gpo.gov/fdsys*. At this site you can view this document, as well as all other documents of this Department published in the **Federal Register**, in text or Adobe Portable Document Format (PDF). To use PDF you must have Adobe Acrobat Reader, which is available free at the site.

You may also access documents of the Department published in the **Federal Register** by using the article search feature at: *www.federalregister.gov*. Specifically, through the advanced search feature at this site, you can limit your search to documents published by the Department.

Dated: January 2, 2014.

Michael K. Yudin,

Acting Assistant Secretary for Special Education and Rehabilitative Services.

[FR Doc. 2014–00056 Filed 1–7–14; 8:45 am]

BILLING CODE 4000–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #2

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER10–2011–005; ER10–2016–003; ER10–2208–001; ER10–2209–001.

Applicants: PPL Montana, LLC, PPL EnergyPlus, LLC, PPL Colstrip I, LLC, PPL Colstrip II, LLC.

Description: Triennial Market-Based Rate Update of the PPL Northwest Companies.

Filed Date: 12/31/13.

Accession Number: 20131231–5188.

Comments Due: 5 p.m. ET 3/3/14.

Docket Numbers: ER10–2895–008; ER11–2292–007; ER11–3942–006; ER11–2293–007; ER10–2917–008; ER11–2294–

007; ER13–1613–001; ER12–2447–005; ER10–2918–009; ER10–2920–008; ER11–3941–006 ;ER10–2921–008; ER10–2922–008; ER10–2966–008.

Applicants: Bear Swamp Power Company LLC, Brookfield Energy Marketing Inc., Brookfield Energy Marketing LP, Brookfield Energy Marketing US LLC, Brookfield Power Piney & Deep Creek LLC, Brookfield Renewable Energy Marketing US LLC, Brookfield White Pine Hydro LLC, Carr Street Generating Station, L.P., Erie Boulevard Hydropower, L.P., Granite Reliable Power, LLC, Great Lakes Hydro America, LLC, Hawks Nest Hydro LLC, Rumford Falls Hydro LLC.

Description: Updated Market Power Analysis for the Northeast Region of the Brookfield Companies.

Filed Date: 12/30/13.

Accession Number: 20131230–5270.

Comments Due: 5 p.m. ET 2/28/14.

Docket Numbers: ER11–2664–008.

Applicants: Powerex Corp.

Description: Updated Market Power Analysis for the Northwest Region and Notice of Non-Material Change in Status of Powerex Corp.

Filed Date: 12/31/13.

Accession Number: 20131231–5148.

Comments Due: 5 p.m. ET 3/3/14.

Docket Numbers: ER11–4267–007; ER11–4270–007; ER11–4269–008; ER11–4268–007; ER11–113–008; ER10–2682–007; ER12–1680–005; ER11–4694–004.

Applicants: Algonquin Energy Services Inc., Algonquin Power Windsor Locks LLC, Algonquin Tinker Gen Co., Algonquin Northern Maine Gen Co., Sandy Ridge Wind, LLC, Granite State Electric Company, Minonk Wind, LLC,GSG 6, LLC.

Description: Triennial Market Power Update for the Northeast Region of the APUC Entities.

Filed Date: 12/31/13.

Accession Number: 20131231–5147.

Comments Due: 5 p.m. ET 3/3/14.

Docket Numbers: ER13–434–001; ER13–412–001; ER13–457–001; ER13–450–001; ER13–518–001; ER13–321–002; ER13–2106–001; ER13–2109–002; ER10–1410–002; ER13–1403–003.

Applicants: Dominion Energy Marketing, Inc., Dominion Nuclear Connecticut, Inc., Dominion Energy Kewaunee, Inc., Dominion Energy Manchester Street, Inc., Dominion Retail, Inc., Fairless Energy, LLC, NedPower Mount Storm, LLC, Fowler Ridge Wind Farm LLC, Virginia Electric and Power Company, Dominion Bridgeport Fuel Cell, LLC.

Description: Triennial Market Power Update for the Northeast Region of the Dominion Companies.

Filed Date: 12/30/13.

Accession Number: 20131230–5267.

Comments Due: 5 p.m. ET 2/28/14.

Docket Numbers: ER14–350–001.

Applicants: NorthWestern Corporation.

Description: NorthWestern Corporation submits Errata to Order No. 764 Compliance Filing (Montana) to be effective 1/7/2014.

Filed Date: 12/31/13.

Accession Number: 20131231–5002.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–906–000.

Applicants: GenConn Energy LLC.

Description: GenConn Energy LLC submits GenConn Tariff Amendment to be effective 1/1/2014.

Filed Date: 12/31/13.

Accession Number: 20131231–5086.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–907–000.

Applicants: Alabama Power Company.

Description: Alabama Power Company submits DEC-SoCo Interconnection Contract Filing to be effective 3/1/2014.

Filed Date: 12/31/13.

Accession Number: 20131231–5108.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–908–000.

Applicants: Alabama Power Company.

Description: Alabama Power Company submits DEF-SoCo Interconnection Contract Filing to be effective 3/1/2014.

Filed Date: 12/31/13.

Accession Number: 20131231–5109.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–909–000.

Applicants: PJM Interconnection, L.L.C.

Description: PJM Interconnection, L.L.C. submits 2013 Annual RTEP Allocation Filing to be effective 1/1/2014.

Filed Date: 12/31/13.

Accession Number: 20131231–5112.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–910–000.

Applicants: Georgia Power Company.

Description: Georgia Power Company submits DEC-SoCo Interconnection Contract Filing to be effective 3/1/2014.

Filed Date: 12/31/13.

Accession Number: 20131231–5114.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–911–000.

Applicants: Georgia Power Company.

Description: Georgia Power Company submits DEF-SoCo Interconnection Contract Filing to be effective 3/1/2014.

Filed Date: 12/31/13.

Accession Number: 20131231–5117.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–912–000.

Applicants: Gulf Power Company.

Description: Gulf Power Company submits DEC-SoCo Interconnection Contract Filing to be effective 3/1/2014.

Filed Date: 12/31/13.

Accession Number: 20131231–5118.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–913–000.

Applicants: Gulf Power Company.

Description: Gulf Power Company submits DEF-SoCo Interconnection Contract Filing to be effective 3/1/2014.

Filed Date: 12/31/13.

Accession Number: 20131231–5119.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–914–000.

Applicants: Mississippi Power Company.

Description: Mississippi Power Company submits DEC-SoCo Interconnection Contract Filing to be effective 3/1/2014.

Filed Date: 12/31/13.

Accession Number: 20131231–5120.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–915–000.

Applicants: Mississippi Power Company.

Description: Mississippi Power Company submits DEF-SoCo Interconnection Contract Filing to be effective 3/1/2014.

Filed Date: 12/31/13.

Accession Number: 20131231–5121.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–916–000.

Applicants: New York State Reliability Council, L.L.C.

Description: Informational filing of Installed Capacity Requirement for the New York Control Area of the New York State Reliability Council, L.L.C.

Filed Date: 12/30/13.

Accession Number: 20131230–5269.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–917–000.

Applicants: Agua Caliente Solar, LLC.

Description: Agua Caliente Solar, LLC submits Aqua Tariff Amendment to be effective 1/1/2014.

Filed Date: 12/31/13.

Accession Number: 20131231–5152.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–918–000.

Applicants: PacifiCorp.

Description: PacifiCorp submits OATT Revised Attachment H–1 (Revised Depreciation Rates) to be effective 1/1/2014.

Filed Date: 12/31/13.

Accession Number: 20131231–5176.

Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–919–000.

Applicants: PacifiCorp.

Description: PacifiCorp submits BPA AC Intertie Agreement 9th Revised to be effective 3/2/2014.

Filed Date: 12/31/13.
Accession Number: 20131231–5190.
Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–920–000.
Applicants: Nevada Power Company.
Description: Nevada Power Company submits Rate Schedule No. 115 RPPA Spring Valley—Cancellation to be effective 1/1/2014.
Filed Date: 12/31/13.
Accession Number: 20131231–5196.
Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–921–000.
Applicants: Arizona Public Service Company.
Description: Arizona Public Service Company submits Cancellation of Edison Navajo Transmission Agreement as APS RS No. 267 to be effective 12/30/2013.
Filed Date: 12/31/13.
Accession Number: 20131231–5197.
Comments Due: 5 p.m. ET 1/21/14.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: December 31, 2013.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2014–00095 Filed 1–7–14; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings #1

Take notice that the Commission received the following electric rate filings:

Docket Numbers: ER10–2822–006; *ER11–2112–005; ER10–2828–001; ER10–2285–004; ER10–2423–004; ER10–2404–004; ER12–2649–001; ER10–1725–001; ER11–2465–005; ER10–2994–010; ER10–3001–002; ER10–3002–001; ER10–3004–002; ER12–422–003; ER10–2301–002; ER10–2273–003; ER10–3010–001; ER11–2306–001; ER12–96–003; ER11–2488–004.*

Applicants: Atlantic Renewable Projects II LLC, Blue Creek Wind Farm LLC, Casselman Windpower LLC, Central Maine Power Company, Flat Rock Windpower LLC, Flat Rock Windpower II LLC, Groton Wind, LLC, Hardscrabble Wind Power LLC, Iberdrola Renewables, LLC, Lempster Wind, LLC, Locust Ridge Wind Farm, LLC, Locust Ridge Wind Farm II, LLC, New England Wind, LLC, New York State Electric & Gas Corporation, PEI Power II, LLC, Providence Heights Wind, LLC, Rochester Gas & Electric Corporation, South Chestnut LLC, Streator-Cayuga Ridge Wind Power LLC.
Description: Updated Market Power Analysis for the Northeast Region of the Iberdrola MBR Sellers.
Filed Date: 12/30/13.
Accession Number: 20131230–5265.
Comments Due: 5 p.m. ET 2/28/14.

Docket Numbers: ER14–898–000.
Applicants: Cactus Energy LLC.
Description: Cactus Energy LLC seeks to cancel its Market-Based Rate Tariff.
Filed Date: 12/30/13.
Accession Number: 20131230–0010.
Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–899–000.
Applicants: AEP Generation Resources Inc.
Description: AEP Generation Resources Inc. submits Wheeling Power Supply Agreement to be effective 1/1/2014.
Filed Date: 12/30/13.
Accession Number: 20131230–5225.
Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–900–000.
Applicants: NRG California South LP.
Description: NRG California South LP submits CA South Tariff Amendment to be effective 12/31/2013.
Filed Date: 12/30/13.
Accession Number: 20131230–5224.
Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–901–000.
Applicants: NRG Marsh Landing LLC.
Description: NRG Marsh Landing LLC submits Marsh Landing Tariff Amendment to be effective 12/31/2013.
Filed Date: 12/30/13.
Accession Number: 20131230–5226.
Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–902–000.
Applicants: NRG Delta LLC.
Description: NRG Delta LLC submits Delta Tariff Amendment to be effective 12/31/2013.
Filed Date: 12/30/13.
Accession Number: 20131230–5228.
Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–903–000.
Applicants: Energy Plus Holdings LLC.
Description: Energy Plus Holdings LLC submits Energy Plus Tariff Amendment to be effective 12/31/2013.
Filed Date: 12/30/13.
Accession Number: 20131230–5229.
Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–904–000.
Applicants: El Segundo Energy Center LLC.
Description: El Segundo Energy Center LLC submits ESEC Tariff Amendment to be effective 12/31/2013.
Filed Date: 12/30/13.
Accession Number: 20131230–5230.
Comments Due: 5 p.m. ET 1/21/14.

Docket Numbers: ER14–905–000.
Applicants: Cabrillo Power II LLC.
Description: Cabrillo Power II LLC submits Cabrillo II Tariff Amendment to be effective 12/31/2013.
Filed Date: 12/30/13.
Accession Number: 20131230–5232.
Comments Due: 5 p.m. ET 1/21/14.

Take notice that the Commission received the following electric securities filings:

Docket Numbers: ES14–20–000.
Applicants: Rochester Gas & Electric Corporation.
Description: Application for Authorization to Issue Short-Term Debt Securities under FPA Section 204 of Rochester Gas and Electric Corporation.
Filed Date: 12/30/13.
Accession Number: 20131230–5264.
Comments Due: 5 p.m. ET 1/21/14.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: December 31, 2013.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2014–00094 Filed 1–7–14; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Combined Notice of Filings

Take notice that the Commission has received the following Natural Gas Pipeline Rate and Refund Report filings:

Filings Instituting Proceedings

Docket Numbers: RP14–334–000.
Applicants: Natural Gas Pipeline Company of America.
Description: Negotiated Rate—Tenaska LPS–RO 142972 to be effective 1/1/2014.
Filed Date: 12/31/13.
Accession Number: 20131231–5127.
Comments Due: 5 p.m. ET 1/13/14.

Docket Numbers: RP14–335–000.
Applicants: Iroquois Gas Transmission System, L.P.
Description: Measurement Variance/Fuel Use Factors of Iroquois Gas Transmission System, L.P.
Filed Date: 12/31/13.
Accession Number: 20131231–5133.
Comments Due: 5 p.m. ET 1/13/14.

Docket Numbers: RP14–336–000.
Applicants: Transcontinental Gas Pipe Line Company.
Description: Negotiated Rates—Cherokee AGL—Replacement Shiippers—Jan 2014 to be effective 1/1/2014.
Filed Date: 12/31/13.
Accession Number: 20131231–5136.
Comments Due: 5 p.m. ET 1/13/14.

Docket Numbers: RP14–337–000.
Applicants: Columbia Gas Transmission, LLC.
Description: Penalty Revenue Crediting Report of Columbia Gas Transmission, LLC.
Filed Date: 12/31/13.
Accession Number: 20131231–5140.
Comments Due: 5 p.m. ET 1/13/14.

Docket Numbers: RP14–338–000.
Applicants: Columbia Gulf Transmission Company, LLC.
Description: Penalty Revenue Crediting Report of Columbia Gulf Transmission, LLC.
Filed Date: 12/31/13.
Accession Number: 20131231–5141.
Comments Due: 5 p.m. ET 1/13/14.

Docket Numbers: RP14–339–000.
Applicants: Central Kentucky Transmission Company.
Description: Penalty Revenue Crediting Report of Central Kentucky Transmission Company.
Filed Date: 12/31/13.
Accession Number: 20131231–5142.
Comments Due: 5 p.m. ET 1/13/14.

Docket Numbers: RP14–340–000.
Applicants: Crossroads Pipeline Company.
Description: Penalty Revenue Crediting Report of Crossroads Pipeline Company.
Filed Date: 12/31/13.
Accession Number: 20131231–5143.
Comments Due: 5 p.m. ET 1/13/14.

Docket Numbers: RP14–341–000.
Applicants: Columbia Gas Transmission, LLC.
Description: CCRM Implementation 2014 to be effective 2/1/2014.
Filed Date: 12/31/13.
Accession Number: 20131231–5150.
Comments Due: 5 p.m. ET 1/13/14.

Docket Numbers: RP14–341–000.
Applicants: Columbia Gas Transmission, LLC.
Description: CCRM Implementation 2014 to be effective 2/1/2014.
Filed Date: 12/31/13.
Accession Number: 20131231–5151.
Comments Due: 5 p.m. ET 1/13/14.

Docket Numbers: RP14–342–000.
Applicants: Cheyenne Plains Gas Pipeline Company, L.
Description: Firm Transportation Service Agreement Update to be effective 1/1/2014.
Filed Date: 12/31/13.
Accession Number: 20131231–5236.
Comments Due: 5 p.m. ET 1/13/14.

Docket Numbers: RP14–343–000.
Applicants: Tennessee Gas Pipeline Company, L.L.C.
Description: Volume No. 2—Seneca Resources Corp—Amend Neg Rate Agmt to be effective 1/1/2014.
Filed Date: 12/31/13.
Accession Number: 20131231–5247.
Comments Due: 5 p.m. ET 1/13/14.

Docket Numbers: RP14–305–000.
Applicants: Equitrans, L.P.
Descriptions: Negotiated Rate Service Agreement—EQT Energy to be effective 1/1/2014.
Filed Date: 12/19/13.
Accession Number: 20131219–5127.
Comments Due: 5 p.m. ET 1/6/14.

Docket Numbers: RP14–322–000.
Applicants: Joint Petition of Tallgrass Interstate Gas Transmission, LLC, Anadarko Energy Services Company, and Wyoming Interstate Company, L.L.C.
Descriptions: Grant of Limited Waiver and Request for Expedited Consideration.
Filed Date: 12/23/2013.
Accession Number: 20131223–5269.
Comment Due: 5 p.m. ET 1/6/2014.

Docket Numbers: RP14–324–000.
Applicants: Natural Gas Pipeline of America LLC.
Descriptions: Negotiated Rate Filing—Tallgrass Interstate Gas. To be effective 12/30/2013.
Filed Date: 12/27/2013.
Accession Number: 20131227–5067.
Comment Due: 5 p.m. ET 1/8/2014.

Docket Numbers: RP14–325–000.
Applicants: Texas Eastern Transmission, LP.
Descriptions: Tariff filing per 154.403: EPC FEB 2014 filing to be effective 2/1/2014.
Filed Date: 12/27/2013.
Accession Number: 20131223–5074.
Comment Due: 5 p.m. ET 1/8/2014.

Any person desiring to intervene or protest in any of the above proceedings must file in accordance with Rules 211 and 214 of the Commission's Regulations (18 CFR 385.211 and 385.214) on or before 5 p.m. Eastern time on the specified comment date. Protests may be considered, but intervention is necessary to become a party to the proceeding.

Filings in Existing Proceedings

Docket Numbers: RP13–1031–002.
Applicants: Trailblazer Pipeline Company LLC.
Description: Compliance and Motion to place tariff sections into effect (Rate Case) to be effective 1/1/2014.
Filed Date: 12/31/13.
Accession Number: 20131231–5177.
Comments Due: 5 p.m. ET 1/13/14.

Any person desiring to protest in any of the above proceedings must file in accordance with Rule 211 of the Commission's Regulations (18 CFR 385.211) on or before 5 p.m. Eastern time on the specified comment date.

The filings are accessible in the Commission's eLibrary system by clicking on the links or querying the docket number.

eFiling is encouraged. More detailed information relating to filing requirements, interventions, protests, service, and qualifying facilities filings can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: January 2, 2014.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2014–00096 Filed 1–7–14; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER14–413–000]

ALLETE Clean Energy, Inc.; Supplemental Notice That Initial Market-Based Rate Filing Includes Request for Blanket Section 204 Authorization

This is a supplemental notice in the above-referenced proceeding of ALLETE Clean Energy, Inc.'s application for market-based rate authority, with an accompanying rate tariff, noting that such application includes a request for blanket authorization, under 18 CFR Part 34, of future issuances of securities and assumptions of liability.

Any person desiring to intervene or to protest should file with the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant.

Notice is hereby given that the deadline for filing protests with regard to the applicant's request for blanket authorization, under 18 CFR part 34, of future issuances of securities and assumptions of liability, is January 22, 2014.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 5 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

The filings in the above-referenced proceeding are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the Web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email *FERCOnlineSupport@ferc.gov.* or call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: January 2, 2014.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2014–00097 Filed 1–7–14; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OA–2014–0001; FRL 9905–27–OA]

Good Neighbor Environmental Board; Notification of Public Advisory Committee Teleconference

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of Public Advisory Committee Teleconference.

SUMMARY: Pursuant to the Federal Advisory Committee Act, Public Law 92–463, notice is hereby given that the Good Neighbor Environmental Board (GNEB) will hold a public teleconference on Friday, January 31, 2014. The meeting will take place from 12 p.m. to 4 p.m. Eastern Standard Time. The meeting is open to the public. For further information regarding the teleconference and background materials, please contact Ann-Marie Gantner at the number listed below.

DATES: Friday, January 31, 2014. The meeting will take place from 12 p.m. to 4 p.m. Eastern Standard Time.

SUPPLEMENTARY INFORMATION:

Background: GNEB is a federal advisory committee chartered under the Federal Advisory Committee Act, PL 92463. GNEB provides advice and recommendations to the President and Congress on environmental and infrastructure issues along the U.S. border with Mexico.

Purpose of Meeting: The purpose of this teleconference is to discuss the Good Neighbor Environmental Board's Sixteenth Report. The report will focus on ecological restoration in the U.S.-Mexico border region.

General Information: The agenda and meeting materials will be available at *http://www.regulations.gov* under Docket ID: EPA–HQ–OA–2014–0001. General information about GNEB can be found on its Web site at *www.epa.gov/ofacmo/gneb.*

If you wish to make oral comments or submit written comments to the Board, please contact Ann-Marie Gantner at least five days prior to the meeting. Written comments should be submitted at *http://www.regulations.gov* under Docket ID: EPA–HQ–OA–2014–0001.

Meeting Access: For information on access or services for individuals with disabilities, please contact Ann-Marie Gantner at (202) 564–4330 or email at *gantner.ann-marie@epa.gov.* To request accommodation of a disability, please contact Ann-Marie Gantner at least 10 days prior to the meeting to give EPA as much time as possible to process your request.

Dated: January 2, 2013.

Ann-Marie Gantner,

Acting Designated Federal Officer.

[FR Doc. 2014–00110 Filed 1–7–14; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2010–0014; FRL–9904–23]

Product Cancellation Order for Certain Pesticide Registrations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: This notice announces EPA's order for the cancellations, voluntarily requested by the registrants and accepted by the Agency, of the products listed in Table 1 of Unit II., pursuant to the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA). This cancellation order follows a June 12, 2013, **Federal Register** Notice of Receipt of Requests from the registrants listed in Table 2 of Unit II., to voluntarily cancel these product registrations. In the June 12, 2013, notice, EPA indicated that it would issue an order implementing the cancellations, unless the Agency received substantive comments within the 180-day comment period that would merit its further review of these requests, or unless the registrants withdrew their requests. The Agency did not receive any comments on the notice. Further, the registrants did not withdraw their requests. Accordingly, EPA hereby issues in this notice a cancellation order granting the requested cancellations. Any distribution, sale, or use of the products subject to this cancellation order is permitted only in accordance with the terms of this order, including any existing stocks provisions.

DATES: The cancellations are effective January 8, 2014.

FOR FURTHER INFORMATION CONTACT: John W. Pates, Jr., Pesticide Re-Evaluation Division (7508P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW.,

Washington, DC 20460–0001; telephone number: (703) 308–8195; email address: *pates.john@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. Since others also may be interested, 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 identification (ID) number EPA–HQ–OPP–2010–0014, 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), EPA West 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 the cancellation, as requested by registrants, of products registered under FIFRA section 3. These registrations are listed in sequence by registration number in Table 1 of this unit.

EPA registration No.	Product name	Chemical name
000264–00668	Liberty ATZ Herbicide	Atrazine, Glufosinate.
000264–00784	Renounce 20WP Insecticide	Cyfluthrin.
000264–00985	GB34 Concentrate Biological Fungicide	Bacillus pumilus strain GB34.
000264–00986	GB34 Technical Biological Fungicide	Bacillus pumilus strain GB34.
000264–01007	Decis 0.2 EC	Deltamethrin.
000264–01008	Decis 0.2 EC Gel	Deltamethrin.
000264–01012	Decis 1.0 Gel Insecticide	Deltamethrin.
000264–01117	Yield Shield FS 200	Bacillus pumilus strain GB34.
000400–00469	Dimilin 25W Mushrooms	Diflubenzuron.
000400–00470	Dimilin 35W for Pasturegrass Mosquitoes	Diflubenzuron.
000400–00471	Micromite 25WS	Diflubenzuron.
000400–00511	Dimilin 80WGS	Diflubenzuron.
000432–00954	Finale Super Concentrate Weed, Grass and Brush Killer	Glufosinate.
000432–00955	Finale Ready-To-Use Weed and Grass Killer	Glufosinate.
000432–00956	Finale Concentrate Weed, Grass and Brush Killer	Glufosinate.
000655–00802	Prentox Larva-Lur Contains Propoxur	Propoxur.
009779–00262	MCPA Amine Herbicide	MCPA, dimethylamine salt.
009779–00265	MCPA LV Ester	MCPA, 2-ethylhexyl ester.
053883–00220	Oryzalin 2G	Oryzalin, Benfluralin.
AL–090001	Reflex Herbicide	Sodium salt of fomesafen.
AR–080004	Reflex Herbicide	Sodium salt of fomesafen.
AR–080005	Superwham! (Alternate Name Forwham! EZ)	Propanil.
AR–080006	Riceshot	Propanil.
AR–080007	Ricepro	Quinclorac, Propanil.
AR–080008	Duet	Propanil, Bensulfuron-methyl.
AR–080009	Superwham! (Alternate Name For Wham! EZ)	Propanil.
AR–080013	Ricebeaux	Propanil, Thiobencarb.
AR–120001	Ricebeaux Herbicide	Thiobencarb, Propanil.
AR–120002	Ricebeaux	Thiobencarb, Propanil.
AR–120003	Ricepro	Quinclorac, Propanil.
CO–060007	Gramoxone Inteon	Paraquat dichloride.
FL–090006	Knockout	Diquat dibromide.
GA–090005	Milestone VM	Triisopropanolamine salt of aminopyralid.
GA–100004	Endigo ZC	Thiamethoxam lambda-Cyhalothrin.
MO–120006	V–10142 AG Herbicide	Imazosulfuron.
ND–020009	Bravo 720	Chlorothalonil.
OR–010006	Cobra Herbicide	Lactofen.
OR–040015	Ethrel Brand Ethephon Plant Regulator	Ethephon.
OR–040031	Rovral 4 Flowable Fungicide	Iprodione.
OR–050017	Simazine 4L	Simazine.
OR–070002	Chateau Herbicide WDG	Flumioxazin.
OR–070019	Acramite-4SC	Bifenazate.
OR–070022	RTU-Vitavax-Thiram Seed Protectant Fungicide	Thiram, Carboxin.
OR–070028	Define SC Herbicide	Flufenacet.
OR–070030	Define SC Herbicide	Flufenacet.
OR–080020	DuPont Direx 4L Herbicide	Diuron.
OR–100004	Chateau Herbicide WDG	Flumioxazin.
OR–120009	Palisade 2EC	Trinexapac-ethyl.
WA–000021	Orthene 97 Pellets	Acephate.
WA–010038	Crossbow	2,4-D butoxyethyl ester acetic acid (3,5,6-trichloro-2-pyridinyl) oxy)-,2-butoxyethel ester.
WA–020012	Echo 720	Chlorothalonil.
WA–060017	Orthene 97	Acephate.
WA–810064	Orthene 75 S Soluble Powder	Acephate.

EPA registration No.	Product name	Chemical name
WA–960024	Orthene 75 S Soluble Powder	Acephate.

Table 2 of this unit includes the names and addresses of record for all registrants of the products in Table 1 of this unit, in sequence by EPA company number. This number corresponds to the first part of the EPA registration numbers of the products listed in Table 1 of this unit.

EPA Company number	Company name and address
264; OR–040015; OR–040031; OR–070022; OR–070028; OR–070030	Bayer CropScience, LP, 2 T.W. Alexander Dr., P.O. Box 12014, Research Triangle Park, NC 27709.
400; OR–070019	Chemtura Corporation, 199 Benson Rd., Middlebury, CT 06749.
432	Bayer Environmental Science, A Division of Bayer CropScience, LP, 2 T.W. Alexander Dr., P.O. Box 12014, Research Triangle Park, NC 27709.
655	Prentis, LLC, Agent: Pyxis Regulatory Consulting, Inc., 4110 136th St. NW., Gig Harbor, WA 98332.
9779; OR–080020	Winfield Solutions, LLC, P.O. Box 64589, St. Paul, MN 55164–0589.
53883	Control Solutions, Inc., 5903 Genoa Red Bluff, Pasadena, TX 77507–1041.
AL–090001; AR–080004; CO–060007; FL–090006; GA–100004; ND–020009; OR–120009.	Syngenta Crop Protection, LLC, 410 Swing Rd., P.O. Box 18300, Greensboro, NC 27419–8300.
AR–080005; AR–080006; AR–080007; AR–080008; AR–080009; AR–080013; AR–120001; AR–120002; AR–120003.	Riceco, LLC, 5100 Poplar Ave., Suite 2428, Memphis, TN 38137.
GA–090005; WA–010038	Dow AgroSciences, LLC, 9330 Zionsville Rd., 308/2E, Indianapolis, IN 46268–1054.
MO–120006; OR–100004; OR–010006; OR–070002	Valent U.S.A. Corporation, 1600 Riviera Ave., Suite 200, Walnut Creek, CA 94596.
OR–050017	Loveland Products, P.O. Box 1286, Greeley, CO 80632–1286.
WA–000021; WA–060017; WA–810064; WA–960024	Amvac Chemical Corporation, 4695 McArthur Ct., Suite 1200, Newport Beach, CA 92660–1706.
WA–020012	Sipcam Agro USA, Inc., 2520 Meridian Parkway, Suite 525, Durham, NC 27713.

III. Summary of Public Comments Received and Agency Response to Comments

During the public comment period provided, EPA received no comments in response to the June 12, 2013, **Federal Register** notice announcing the Agency's receipt of the requests for voluntary cancellations of products listed in Table 1 of Unit II.

IV. Cancellation Order

Pursuant to FIFRA section 6(f), EPA hereby approves the requested cancellations of the registrations identified in Table 1 of Unit II. Accordingly, the Agency hereby orders that the product registrations identified in Table 1 of Unit II. are canceled. The effective date of the cancellations that are the subject of this notice is January 8, 2014. Any distribution, sale, or use of existing stocks of the products identified in Table 1 of Unit II. in a manner inconsistent with any of the provisions for disposition of existing stocks set forth in Unit VI. will be a violation of FIFRA.

V. 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 or amended to terminate one or more uses. 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, following the public comment period, the EPA Administrator may approve such a request. The notice of receipt for this action was published for comment in the **Federal Register** of June 12, 2013 (78 FR 35265) (FRL–9388–6). The comment period closed on December 9, 2013.

VI. Provisions for Disposition of Existing Stocks

Existing stocks are those stocks of registered pesticide products which are currently in the United States and which were packaged, labeled, and released for shipment prior to the effective date of the cancellation action. The existing stocks provisions for the products subject to this order are as follows.

The registrants may continue to sell and distribute existing stocks of products listed in Table 1 of Unit II. until January 8, 2015, which is 1 year after the publication of the Cancellation Order in the **Federal Register**. Thereafter, the registrants are prohibited from selling or distributing products listed in Table 1, except for export in accordance with FIFRA section 17, or proper disposal. Persons other than the registrants may sell, distribute, or use existing stocks of products listed in Table 1 of Unit II. until existing stocks are exhausted, provided that such sale, distribution, or use is consistent with the terms of the previously approved labeling on, or that accompanied, the canceled products.

List of Subjects

Environmental protection, Pesticides and pests.

Dated: December 20, 2013.

Richard P. Keigwin, Jr.,

Director, Pesticide Re-Evaluation Division, Office of Pesticide Programs.

[FR Doc. 2014–00033 Filed 1–7–14; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Advisory Committee to the Director, Centers for Disease Control and Prevention—Health Disparities Subcommittee

In accordance with section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463), the Centers for Disease Control and Prevention (CDC) announces the following meeting of the aforementioned subcommittee:

Time and Date: 10:00 a.m.–12:00 p.m. EDT, February 13, 2014.

Place: Teleconference.

Status: This meeting is open to the public, limited only by the availability of telephone ports. The public is welcome to participate during the public comment period, which is tentatively scheduled from 11:45 a.m. to 11:55 a.m. To participate on the teleconference, please dial (866) 763–0273 and enter code 6158968.

Purpose: The Subcommittee will provide advice to the CDC Director through the Advisory Committee to the Director (ACD) on strategic and other health disparities and health equity issues and provide guidance on opportunities for CDC.

Matters To Be Discussed: The Health Disparities Subcommittee (HSD) members will discuss some of the current health equity activities at CDC, as well as discuss health equity recommendations to the CDC ACD.

The agenda is subject to change as priorities dictate.

Contact Person for More Information: Leandris Liburd, Ph.D., M.P.H., M.A., Designated Federal Officer, Health Disparities Subcommittee, ACD, CDC, 1600 Clifton Road NE., M/S K–77, Atlanta, Georgia 30333, Telephone (770) 488–8182, Email: *LEL1@cdc.gov*.

The Director, Management Analysis and Services Office, has been delegated the authority to sign **Federal Register** notices pertaining to announcements of meetings and other committee management activities, for both the Centers for Disease Control and Prevention and the Agency for Toxic Substances and Disease Registry.

Gary J. Johnson,

Acting Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. 2014–00043 Filed 1–7–14; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Advisory Board on Radiation and Worker Health, National Institute for Occupational Safety and Health

In accordance with section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463), and pursuant to the requirements of 42 CFR 83.15(a), the Centers for Disease Control and Prevention (CDC), announces the following meeting of the Advisory Board on Radiation and Worker Health (ABRWH or Advisory Board), National Institute for Occupational Safety and Health (NIOSH):

Time and Date: (All times are Central Standard Time) 9 a.m.–5:30 p.m., January 28, 2014.

Public Comment Time and Date: (All times are Central Standard Time) 5:30 p.m.–6:30 p.m., January 28, 2014.

**Please note that the public comment period may end before the time indicated, following the last call for comments. Members of the public who wish to provide public comments should plan to attend the public comment session at the start time listed.*

Place: Crowne Plaza, 1301 Wyandotte, Kansas City, MO, 64105 Phone: 816–460–6664; Fax: 816–474–0424. Audio Conference Call via FTS Conferencing. The USA toll-free, dial-in number is 1–866–659–0537 with a pass code of 9933701. Live Meeting Connection: *https://www.livemeeting.com/cc/cdc/join?id=JKQMG2&role=attend&pw=ABRWH; Meeting ID: JKQMG2; Entry Code: ABRWH*

Status: Open to the public, limited only by the space available. The meeting space accommodates approximately 150 people.

Background: The Advisory Board was established under the Energy Employees Occupational Illness Compensation Program Act of 2000 to advise the President on a variety of policy and technical functions required to implement and effectively manage the new compensation program. Key functions of the Advisory Board include providing advice on the development of probability of causation guidelines which have been promulgated by the Department of Health and Human Services (HHS) as a final rule, advice on methods of dose reconstruction which have also been promulgated by HHS as a final rule, advice on the scientific validity and quality of dose estimation and reconstruction efforts being performed for purposes of the compensation program, and advice on petitions to add classes of workers to the Special Exposure Cohort (SEC).

In December 2000, the President delegated responsibility for funding, staffing, and operating the Advisory Board to HHS, which subsequently delegated this authority to the CDC. NIOSH implements this responsibility for CDC. The charter was issued on August 3, 2001, renewed at appropriate intervals, and will expire on August 3, 2015.

Purpose: This Advisory Board is charged with a) providing advice to the Secretary, HHS, on the development of guidelines under Executive Order 13179; b) providing advice to the Secretary, HHS, on the scientific validity and quality of dose reconstruction efforts performed for this program; and c) upon request by the Secretary, HHS, advise the Secretary on whether there is a class of employees at any Department of Energy facility who were exposed to radiation but for whom it is not feasible to estimate their radiation dose, and on whether there is reasonable likelihood that such radiation doses may have endangered the health of members of this class.

Matters To Be Discussed: The agenda for the Advisory Board meeting includes: NIOSH Program Update; Department of Labor Program Update; Department of Energy Program Update; SEC petitions for: Joslyn Manufacturing and Supply Company (Fort Wayne, IN) and Kansas City Plant (Kansas City, MO); SEC Issues Work Group Report on ''Sufficient Accuracy''/Co-Worker Dose Modeling; SEC Petitions Update, and Board Work Sessions.

The agenda is subject to change as priorities dictate.

In the event an individual cannot attend, written comments may be submitted in accordance with the redaction policy provided below. Any written comments received will be provided at the meeting and should be submitted to the contact person below well in advance of the meeting.

Policy on Redaction of Board Meeting Transcripts (Public Comment): (1) If a person making a comment gives his or her personal information, no attempt will be made to redact the name; however, NIOSH will redact other personally identifiable information, such as contact information, social security numbers, case numbers, etc., of the commenter.

(2) If an individual in making a statement reveals personal information (e.g., medical or employment information) about themselves that information will not usually be redacted. The NIOSH Freedom of Information Act (FOIA) coordinator will, however, review such revelations in accordance with the Federal Advisory Committee Act and if deemed appropriate, will redact such information.

(3) If a commenter reveals personal information concerning a living third party, that information will be reviewed by the NIOSH FOIA coordinator, and upon determination, if deemed appropriate, such information will be redacted, unless the disclosure is made by the third party's authorized representative under the Energy Employees Occupational Illness Compensation Program Act (EEOICPA) program.

(4) In general, information concerning a deceased third party may be disclosed; however, such information will be redacted if (a) the disclosure is made by an individual other than the survivor claimant, a parent, spouse, or child, or the authorized representative of the deceased third party; (b)

if it is unclear whether the third party is living or deceased; or (c) the information is unrelated or irrelevant to the purpose of the disclosure.

The Board will take reasonable steps to ensure that individuals making public comment are aware of the fact that their comments (including their name, if provided) will appear in a transcript of the meeting posted on a public Web site. Such reasonable steps include: (a) A statement read at the start of each public comment period stating that transcripts will be posted and names of speakers will not be redacted; (b) A printed copy of the statement mentioned in (a) above will be displayed on the table where individuals sign up to make public comments; (c) A statement such as outlined in (a) above will also appear with the agenda for a Board Meeting when it is posted on the NIOSH Web site; (d) A statement such as in (a) above will appear in the **Federal Register** Notice that announces Board and Subcommittee meetings.

Contact Person For More Information: Theodore Katz, M.P.A., Designated Federal Officer, NIOSH, CDC, 1600 Clifton Road NE., MS E–20, Atlanta, GA 30333, Telephone: (513) 533–6800, Toll Free: 1–800–CDC–INFO, Email: *dcas@cdc.gov*.

The Director, Management Analysis and Services Office, has been delegated the authority to sign **Federal Register** Notices pertaining to announcements of meetings and other committee management activities, for both the Centers for Disease Control and Prevention and the Agency for Toxic Substances and Disease Registry.

Gary J. Johnson,

Acting Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. 2014–00042 Filed 1–7–14; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Request for Nominations of Candidates To Serve on the CDC/HRSA Advisory Committee on HIV, Viral Hepatitis and STD Prevention and Treatment, Centers for Disease Control and Prevention, Health Resources and Services Administration

The Centers for Disease Control and Prevention (CDC) is soliciting nominations for possible membership on the CDC/HRSA Advisory Committee on HIV, Viral Hepatitis and STD Prevention and Treatment (CHACHSPT).

The CHACHSPT provides advice to the Secretary, HHS; the Director, CDC; and the Administrator, Health Resources and Services Administration (HRSA), on objectives, strategies, policies, and priorities for HIV, Viral Hepatitis, and STD prevention and treatment efforts including surveillance of HIV infection, AIDS, Viral Hepatitis, other STDs, and related behaviors; epidemiologic, behavioral, health services, and laboratory research on HIV/AIDS, Viral Hepatitis, and other STDs; identification of policy issues related to HIV/Viral Hepatitis/STD professional education, patient healthcare delivery, and prevention services; agency policies about prevention of HIV/AIDS, Viral Hepatitis and other STDs, treatment, healthcare delivery, and research and training; strategic issues influencing the ability of CDC and HRSA to fulfill their missions of providing prevention and treatment services; programmatic efforts to prevent and treat HIV, Viral Hepatitis, and other STDs; and support to the agencies in their development of responses to emerging health needs related to HIV, Viral Hepatitis and other STDs.

The CHACHSPT consists of 18 experts knowledgeable in the fields of public health, epidemiology, laboratory practices, immunology, infectious diseases, drug abuse, behavioral science, health education, healthcare delivery, state health programs, clinical care, preventive health, medical education, health services and clinical research, and healthcare financing, who are selected by the Secretary of the U.S. Department of Health and Human Services (HHS).

Nominations are being sought for individuals who have expertise and qualifications necessary to contribute to the accomplishments of the Committee's objectives.

Nominees will be selected from experts having experience in HIV/AIDS, Viral Hepatitis and STD prevention, control and treatment. Experts in the disciplines of epidemiology, laboratory practice, immunology, infectious diseases, drug abuse, behavioral science, health education, healthcare delivery, state health programs, clinical care, preventive health, medical education, health services and clinical research, healthcare financing and other related disciplines will be considered. The committee shall have at least four members who shall be persons living with HIV/AIDS.

Members may be invited to serve for terms of up to four years. The HHS policy stipulates that committee membership be balanced in terms of professional training and background, points of view represented and the committee's function. Consideration is given to a broad representation of geographic areas within the U.S., with equitable representation of the sexes, ethnic and racial minorities, and persons with disabilities. Nominees must be U.S. citizens, and cannot be full-time employees of the U.S. Government.

Candidates should submit the following items:

- Current *curriculum vitae,* including complete contact information (telephone numbers, mailing address, email address)
- A letter of recommendation from person(s) not employed by the U.S. Department of Health and Human Services
- A statement indicating the nominee's willingness to serve as a potential member of the Committee.

Nominations should be submitted electronically to *zkr7@cdc.gov* or in writing, to: Margie Scott-Cseh, Committee Management Specialist, NCHHSTP, CDC, 1600 Clifton Road NE., Mailstop: E07, Atlanta, GA 30333. All nominations must be postmarked by April 30, 2014.

The Director, Management Analysis and Services Office, has been delegated the authority to sign **Federal Register** notices pertaining to announcements of meetings and other committee management activities, for both the Centers for Disease Control and Prevention, and the Agency for Toxic Substances and Disease Registry.

Gary J. Johnson

Acting Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. 2014–00045 Filed 1–7–14; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Request for Nominations of Candidates To Serve on the Advisory Council for the Elimination of Tuberculosis, Centers for Disease Control and Prevention, Department of Health and Human Services

The Centers for Disease Control and Prevention (CDC) is soliciting nominations for possible membership on the Advisory Council for the Elimination of Tuberculosis (ACET).

ACET provides advice and recommendations to the Secretary, Department of Health and Human Services (HHS); the Assistant Secretary of Health; and the Director, CDC, regarding program policies, strategies, objectives, and priorities; address the development and application of new

technologies; provide guidance and review on CDC's Tuberculosis Prevention Research portfolio and program priorities; and review the extent to which progress has been made toward eliminating tuberculosis.

ACET consists of 10 experts knowledgeable in the fields of public Health, epidemiology, immunology, infectious diseases, pulmonary disease, pediatrics, tuberculosis, microbiology, or preventive health care delivery, who are selected by the Secretary of the United State Department of Health and Human Services.

Nominations are being sought for individuals who have expertise and qualifications necessary to contribute to the accomplishments of the Council's objectives.

Nominees will be selected from experts having experience in tuberculosis prevention and control.

Experts in the disciplines of epidemiology, immunology, infectious diseases, pulmonary disease, pediatrics, tuberculosis, microbiology, preventive health care delivery, and experts in public health and other related disciplines will be considered. Members may be invited to serve up to four-year terms. The HHS policy stipulates that committee membership be balanced in terms of professional training and background, points of view represented and the council's function. Consideration is given to a broad representation of geographic areas within the U.S., with equitable representation of the sexes, ethnic and racial minorities, and persons with disabilities. Nominees must be U.S. citizens, and cannot be full-time employees of the U.S. Government.

Candidates should submit the following items:

- Current curriculum vitae, including complete contact information (telephone numbers, mailing address, email address)
- A letter of recommendation from person(s) not employed by the U.S. Department of Health and Human Services
- A statement indicating the nominee's willingness to serve as a potential member of the Council.

Nominations should be submitted electronically or in writing, and must be postmarked by September 30, 2014, to: Margie Scott-Cseh, Committee Management Specialist, NCHHSTP, CDC, 1600 Clifton Road NE., Mailstop: E07, Atlanta, GA 30333, Email address: *zkr7@cdc.gov*.

The Director, Management Analysis and Services Office, has been delegated the authority to sign **Federal Register** notices pertaining to announcements of meetings and other committee management activities, for both the Centers for Disease Control and Prevention, and the Agency for Toxic Substances and Disease Registry.

Gary J. Johnson,

Acting Director, Management Analysis and Services Office, Centers for Disease Control and Prevention.

[FR Doc. 2014–00044 Filed 1–7–14; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Administration for Community Living

Agency Information Collection Activities; Submission for OMB Review; Comment Request; Extension of Current Funding Opportunity Announcement and Grant Application Template for ACL Discretionary Grant Programs

AGENCY: Administration for Community Living, HHS.

ACTION: Notice.

SUMMARY: The Administration for Community Living (ACL) is announcing that the proposed collection of information listed below has been submitted to the Office of Management and Budget (OMB) for review and clearance under the Paperwork Reduction Act of 1995.

DATES: Submit written comments on the collection of information by February 7, 2014.

ADDRESSES: Submit written comments on the collection of information by fax 202.395.6974 or by mail to the Office of Information and Regulatory Affairs, OMB, New Executive Office Bldg., 725 17th St. NW., Rm. 10235, Washington, DC 20503, Attn: Carolyn Lovett, Desk Officer for ACL.

FOR FURTHER INFORMATION CONTACT: Lori Stalbaum, (202) 357–3452 or *lori.stalbam@acl.hhs.gov*.

SUPPLEMENTARY INFORMATION: In compliance with 44 U.S.C. 3507, ACL has submitted the following proposed collection of information to OMB for review and clearance.

ACL is requesting an extension of the currently approved Administration on Aging (AoA) Funding Opportunity Announcement and Application Instructions Template for use for all ACL Discretionary Grant Programs, of which AoA is now a program center. This template provides the requirements and instructions for the submission of an application for discretionary grants funding opportunities. The template may be found on the ACL Web site at *www.acl.gov/Funding_Opportunities/Announcements/docs/ACL_PA_Template_FINAL_8-12–13.doc.* ACL estimates the burden of this collection of information as follows:

Frequency: 15—20 Funding Opportunity Announcements published annually.

Respondents: State agencies, public agencies, private non-profit agencies, institutions of higher education, and organizations including tribal organizations.

Estimated Number of Responses: 350 annually.

Total Estimated Burden Hours: 16,800.

Dated: January 2, 2014.

Kathy Greenlee,

Administrator and Assistant Secretary for Aging.

[FR Doc. 2014–00059 Filed 1–7–14; 8:45 am]

BILLING CODE 4154–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2014–N–0001]

Nonprescription Drugs Advisory Committee; Notice of Meeting

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

This notice announces a forthcoming meeting of a public advisory committee of the Food and Drug Administration (FDA). The meeting will be open to the public.

Name of Committee: Nonprescription Drugs Advisory Committee.

General Function of the Committee: To provide advice and recommendations to the Agency on FDA's regulatory issues.

Date and Time: The meeting will be held on February 26, 2014, from 8 a.m. to 12:30 p.m.

Location: FDA White Oak Campus, 10903 New Hampshire Ave., Building 31 Conference Center, the Great Room (Rm. 1503), Silver Spring, MD 20993–0002. Information regarding special accommodations due to a disability, visitor parking, and transportation may be accessed at: *http://www.fda.gov/AdvisoryCommittees/default.htm;* under the heading ''Resources for You,'' click on ''Public Meetings at the FDA White Oak Campus.'' Please note that visitors to the White Oak Campus must enter through Building 1.

Contact Person: Glendolynn S. Johnson, Center for Drug Evaluation and

Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 31, Rm. 2417, Silver Spring, MD 20993–0002, 301–796–9001, FAX: 301–847–8533, email: *NDAC@fda.hhs.gov,* or FDA Advisory Committee Information Line, 1–800–741–8138 (301–443–0572 in the Washington, DC area). A notice in the **Federal Register** about last minute modifications that impact a previously announced advisory committee meeting cannot always be published quickly enough to provide timely notice. Therefore, you should always check the Agency's Web site at *http://www.fda.gov/AdvisoryCommittees/default.htm* and scroll down to the appropriate advisory committee meeting link, or call the advisory committee information line to learn about possible modifications before coming to the meeting.

Agenda: On February 26, 2014, the committee will meet to discuss whether over-the-counter (OTC) bronchodilators administered by hand-held rubber bulb nebulizers for the temporary relief of mild symptoms of intermittent asthma (shortness of breath, tightness of chest, and wheezing) should be removed from the monograph. Specific drugs to be discussed include epinephrine, epinephrine bitartrate, and racepinephrine hydrochloride (21 CFR 341.16).

FDA intends to make background material available to the public no later than 2 business days before the meeting. If FDA is unable to post the background material on its Web site prior to the meeting, the background material will be made publicly available at the location of the advisory committee meeting, and the background material will be posted on FDA's Web site after the meeting. Background material is available at *http://www.fda.gov/AdvisoryCommittees/Calendar/default.htm.* Scroll down to the appropriate advisory committee meeting link.

Procedure: Interested persons may present data, information, or views, orally or in writing, on issues pending before the committee. Written submissions may be made to the contact person on or before February 10, 2014. Oral presentations from the public will be scheduled between approximately 10:15 a.m. and 11:15 a.m. Those individuals interested in making formal oral presentations should notify the contact person and submit a brief statement of the general nature of the evidence or arguments they wish to present, the names and addresses of proposed participants, and an indication of the approximate time requested to make their presentation on or before January 31, 2014. Time allotted for each presentation may be limited. If the number of registrants requesting to speak is greater than can be reasonably accommodated during the scheduled open public hearing session, FDA may conduct a lottery to determine the speakers for the scheduled open public hearing session. The contact person will notify interested persons regarding their request to speak by February 3, 2014.

Persons attending FDA's advisory committee meetings are advised that the Agency is not responsible for providing access to electrical outlets.

FDA welcomes the attendance of the public at its advisory committee meetings and will make every effort to accommodate persons with physical disabilities or special needs. If you require special accommodations due to a disability, please contact Glendolynn S. Johnson at least 7 days in advance of the meeting.

FDA is committed to the orderly conduct of its advisory committee meetings. Please visit our Web site at *http://www.fda.gov/AdvisoryCommittees/AboutAdvisoryCommittees/ucm111462.htm* for procedures on public conduct during advisory committee meetings.

Notice of this meeting is given under the Federal Advisory Committee Act (5 U.S.C. app. 2).

Dated: January 3, 2014.

Jill Hartzler Warner,

Acting Associate Commissioner for Special Medical Programs.

[FR Doc. 2014–00090 Filed 1–7–14; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2014–N–0001]

Anesthesiology and Respiratory Therapy Devices Panel of the Medical Devices Advisory Committee; Notice of Meeting

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

This notice announces a forthcoming meeting of a public advisory committee of the Food and Drug Administration (FDA). The meeting will be open to the public.

Name of Committee: Anesthesiology and Respiratory Therapy Devices Panel of the Medical Devices Advisory Committee.

General Function of the Committee: To provide advice and recommendations to the Agency on FDA's regulatory issues.

Date and Time: The meeting will be held on February 20, 2014, from 8 a.m. to 6 p.m.

Location: FDA White Oak Campus, 10903 New Hampshire Ave., Bldg. 31 Conference Center, the Great Room (Rm. 1503), Silver Spring, MD 20993. Information regarding special accommodations due to a disability, visitor parking, and transportation may be accessed at: *http://www.fda.gov/AdvisoryCommittees/default.htm;* under the heading ''Resources for You,'' click on ''Public Meetings at the FDA White Oak Campus.'' Please note that visitors to the White Oak Campus must enter through Building 1.

Contact Person: Shanika Craig, Food and Drug Administration, Center for Devices and Radiological Health, 10903 New Hampshire Ave., Bldg. 66, Rm. 1613, Silver Spring, MD 20993, 301–796–6639, *Shanika.Craig@fda.hhs.gov,* or FDA Advisory Committee Information Line, 1–800–741–8138 (301–443–0572 in the Washington, DC area). A notice in the **Federal Register** about last minute modifications that impact a previously announced advisory committee meeting cannot always be published quickly enough to provide timely notice. Therefore, you should always check the Agency's Web site at *http://www.fda.gov/AdvisoryCommittees/default.htm* and scroll down to the appropriate advisory committee meeting link, or call the advisory committee information line to learn about possible modifications before coming to the meeting.

Agenda: On February 20, 2014, the committee will discuss, make recommendations, and vote on information related to the premarket approval application regarding the Inspire II Upper Airway Stimulator, sponsored by Inspire Medical Systems, Inc. The Inspire II Upper Airway Stimulator is a permanently implanted device intended to treat moderate to severe obstructive sleep apnea in patients who are not effectively treated by continuous positive airway pressure devices. The device stimulates the hypoglossal nerve synchronous with inspiration in order to contract the patient's upper airway muscles and help maintain airway patency during sleep.

FDA intends to make background material available to the public no later than 2 business days before the meeting. If FDA is unable to post the background material on its Web site prior to the meeting, the background material will be made publicly available at the

location of the advisory committee meeting, and the background material will be posted on FDA's Web site after the meeting. Background material is available at *http://www.fda.gov/AdvisoryCommittees/Calendar/default.htm.* Scroll down to the appropriate advisory committee meeting link.

Procedure: Interested persons may present data, information, or views, orally or in writing, on issues pending before the committee. Written submissions may be made to the contact person on or before February 10, 2014. On February 20, 2014, oral presentations from the public will be scheduled between approximately 1 p.m. and 2 p.m. Those individuals interested in making formal oral presentations should notify the contact person and submit a brief statement of the general nature of the evidence or arguments they wish to present, the names and addresses of proposed participants, and an indication of the approximate time requested to make their presentation on or before January 31, 2014. Time allotted for each presentation may be limited. If the number of registrants requesting to speak is greater than can be reasonably accommodated during the scheduled open public hearing session, FDA may conduct a lottery to determine the speakers for the scheduled open public hearing session. The contact person will notify interested persons regarding their request to speak by February 3, 2014.

Persons attending FDA's advisory committee meetings are advised that the Agency is not responsible for providing access to electrical outlets.

FDA welcomes the attendance of the public at its advisory committee meetings and will make every effort to accommodate persons with physical disabilities or special needs. If you require special accommodations due to a disability, please contact James Clark, Committee Management Staff, *james.clark@fda.hhs.gov,* or 301–796–5293 at least 7 days in advance of the meeting.

FDA is committed to the orderly conduct of its advisory committee meetings. Please visit our Web site at *http://www.fda.gov/AdvisoryCommittees/AboutAdvisoryCommittees/ucm111462.htm* for procedures on public conduct during advisory committee meetings.

Notice of this meeting is given under the Federal Advisory Committee Act (5 U.S.C. app. 2).

Dated: January 3, 2014.

Jill Hartzler Warner,

Acting Associate Commissioner for Special Medical Programs.

[FR Doc. 2014–00089 Filed 1–7–14; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2014–N–0001]

Joint Meeting of the Nonprescription Drugs Advisory Committee and the Pulmonary-Allergy Drugs Advisory Committee; Notice of Meeting

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

This notice announces a forthcoming meeting of public advisory committees of the Food and Drug Administration (FDA). The meeting will be open to the public.

Name of Committees: Nonprescription Drugs Advisory Committee and the Pulmonary-Allergy Drugs Advisory Committee.

General Function of the Committees: To provide advice and recommendations to the Agency on FDA's regulatory issues.

Date and Time: The meeting will be held on February 25, 2014, from 8:30 a.m. to 5 p.m.

Location: FDA White Oak Campus, 10903 New Hampshire Ave., Bldg. 31 Conference Center, the Great Room (Rm. 1503), Silver Spring, MD 20993–0002. Information regarding special accommodations due to a disability, visitor parking, and transportation may be accessed at: *http://www.fda.gov/AdvisoryCommittees/default.htm;* under the heading ''Resources for You,'' click on ''Public Meetings at the FDA White Oak Campus.'' Please note that visitors to the White Oak Campus must enter through Building 1.

Contact Person: Glendolynn S. Johnson, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 31, Rm. 2417, Silver Spring, MD 20993–0002, 301–796–9001, FAX: 301–847–8533, email: *NDAC@fda.hhs.gov,* or FDA Advisory Committee Information Line, 1–800–741–8138 (301–443–0572 in the Washington, DC area). A notice in the **Federal Register** about last minute modifications that impact a previously announced advisory committee meeting cannot always be published quickly enough to provide timely notice. Therefore, you should always check the Agency's Web site at *http://www.fda.gov/AdvisoryCommittees/default.htm* and scroll down to the appropriate advisory committee meeting link, or call the advisory committee information line to learn about possible modifications before coming to the meeting.

Agenda: The committees will discuss data submitted by Armstrong Pharmaceuticals, Inc., to support a new drug application (NDA) 205920, for over-the-counter (OTC) marketing of epinephrine inhalation aerosol 125 microgram (mcg)/actuation (proposed trade name Primatene HFA), for temporary relief of mild symptoms of intermittent asthma for consumers 12 years of age and older. The epinephrine inhaler was developed as a replacement for Primatene Mist (epinephrine metered inhaler 200 mcg/actuation), an OTC product that was phased out in December 2011 because of the use of chlorofluorocarbons as the propellant. The committee will be asked to consider whether the data support an acceptable risk/benefit profile of the epinephrine inhaler for use by OTC consumers.

FDA intends to make background material available to the public no later than 2 business days before the meeting. If FDA is unable to post the background material on its Web site prior to the meeting, the background material will be made publicly available at the location of the advisory committee meeting, and the background material will be posted on FDA's Web site after the meeting. Background material is available at *http://www.fda.gov/AdvisoryCommittees/Calendar/default.htm.* Scroll down to the appropriate advisory committee meeting link.

Procedure: Interested persons may present data, information, or views, orally or in writing, on issues pending before the committee. Written submissions may be made to the contact person on or before February 10, 2014. Oral presentations from the public will be scheduled between approximately 1 p.m. and 2 p.m. Those individuals interested in making formal oral presentations should notify the contact person and submit a brief statement of the general nature of the evidence or arguments they wish to present, the names and addresses of proposed participants, and an indication of the approximate time requested to make their presentation on or before January 31, 2014. Time allotted for each presentation may be limited. If the number of registrants requesting to speak is greater than can be reasonably accommodated during the scheduled

open public hearing session, FDA may conduct a lottery to determine the speakers for the scheduled open public hearing session. The contact person will notify interested persons regarding their request to speak by February 3, 2014.

Persons attending FDA's advisory committee meetings are advised that the Agency is not responsible for providing access to electrical outlets.

FDA welcomes the attendance of the public at its advisory committee meetings and will make every effort to accommodate persons with physical disabilities or special needs. If you require special accommodations due to a disability, please contact Glendolynn S. Johnson at least 7 days in advance of the meeting.

FDA is committed to the orderly conduct of its advisory committee meetings. Please visit our Web site at *http://www.fda.gov/AdvisoryCommittees/AboutAdvisoryCommittees/ucm111462.htm* for procedures on public conduct during advisory committee meetings.

Notice of this meeting is given under the Federal Advisory Committee Act (5 U.S.C. app. 2).

Dated: January 3, 2014.

Jill Hartzler Warner,

Acting Associate Commissioner for Special Medical Programs.

[FR Doc. 2014–00091 Filed 1–7–14; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2014–N–0001]

Cardiovascular and Renal Drugs Advisory Committee; Notice of Meeting

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

This notice announces a forthcoming meeting of a public advisory committee of the Food and Drug Administration (FDA). The meeting will be open to the public.

Name of Committee: Cardiovascular and Renal Drugs Advisory Committee.

General Function of the Committee: To provide advice and recommendations to the Agency on FDA's regulatory issues.

Date and Time: The meeting will be held on February 13, 2014, from 8 a.m. to 5 p.m.

Location: FDA White Oak Campus, 10903 New Hampshire Ave., Building 31 Conference Center, the Great Room (Rm. 1503), Silver Spring, MD 20993–0002. Information regarding special accommodations due to a disability, visitor parking, and transportation may be accessed at: *http://www.fda.gov/AdvisoryCommittees/default.htm;* under the heading ''Resources for You,'' click on ''Public Meetings at the FDA White Oak Campus.'' Please note that visitors to the White Oak Campus must enter through Building 1.

Contact Person: Kristina Toliver, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 31, Rm. 2417, Silver Spring, MD 20993–0002, 301–796–9001, FAX: 301–847–8533, *CRDAC@fda.hhs.gov,* or FDA Advisory Committee Information Line, 1–800–741–8138 (301–443–0572 in the Washington, DC area).

A notice in the **Federal Register** about last minute modifications that impact a previously announced advisory committee meeting cannot always be published quickly enough to provide timely notice. Therefore, you should always check the Agency's Web site at *http://www.fda.gov/AdvisoryCommittees/default.htm* and scroll down to the appropriate advisory committee meeting link, or call the advisory committee information line to learn about possible modifications before coming to the meeting.

Agenda: The committee will discuss biologics license application 125468, serelaxin injection, submitted by Novartis, as a treatment to improve the symptoms of acute heart failure through reduction of the rate of worsening of heart failure.

FDA intends to make background material available to the public no later than 2 business days before the meeting. If FDA is unable to post the background material on its Web site prior to the meeting, the background material will be made publicly available at the location of the advisory committee meeting, and the background material will be posted on FDA's Web site after the meeting. Background material is available at *http://www.fda.gov/AdvisoryCommittees/Calendar/default.htm.* Scroll down to the appropriate advisory committee meeting link.

Procedure: Interested persons may present data, information, or views, orally or in writing, on issues pending before the committee. Written submissions may be made to the contact person on or before January 29, 2014. Oral presentations from the public will be scheduled between approximately 1 p.m. and 2 p.m. Those individuals interested in making formal oral presentations should notify the contact person and submit a brief statement of the general nature of the evidence or arguments they wish to present, the names and addresses of proposed participants, and an indication of the approximate time requested to make their presentation on or before January 21, 2014. Time allotted for each presentation may be limited. If the number of registrants requesting to speak is greater than can be reasonably accommodated during the scheduled open public hearing session, FDA may conduct a lottery to determine the speakers for the scheduled open public hearing session. The contact person will notify interested persons regarding their request to speak by January 22, 2014.

Persons attending FDA's advisory committee meetings are advised that the Agency is not responsible for providing access to electrical outlets.

FDA welcomes the attendance of the public at its advisory committee meetings and will make every effort to accommodate persons with physical disabilities or special needs. If you require special accommodations due to a disability, please contact Kristina Toliver at least 7 days in advance of the meeting.

FDA is committed to the orderly conduct of its advisory committee meetings. Please visit our Web site at *http://www.fda.gov/AdvisoryCommittees/AboutAdvisoryCommittees/ucm111462.htm* for procedures on public conduct during advisory committee meetings.

Notice of this meeting is given under the Federal Advisory Committee Act (5 U.S.C. app. 2).

Dated: January 3, 2014.

Jill Hartzler Warner,

Acting Associate Commissioner for Special Medical Programs.

[FR Doc. 2014–00101 Filed 1–7–14; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2014–N–0001]

Joint Meeting of the Arthritis Advisory Committee and the Drug Safety and Risk Management Advisory Committee; Notice of Meeting

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

This notice announces a forthcoming meeting of public advisory committees of the Food and Drug Administration

(FDA). The meeting will be open to the public.

Name of Committees: Arthritis Advisory Committee and the Drug Safety and Risk Management Advisory Committee.

General Function of the Committees: To provide advice and recommendations to the Agency on FDA's regulatory issues.

Date and Time: The meeting will be held on February 10 and 11, 2014, from 8 a.m. to 5 p.m.

Location: FDA White Oak Campus, 10903 New Hampshire Ave., Bldg. 31 Conference Center, the Great Room (Rm. 1503), Silver Spring, MD 20993–0002. Information regarding special accommodations due to a disability, visitor parking, and transportation may be accessed at: *http://www.fda.gov/AdvisoryCommittees/default.htm;* under the heading ''Resources for You,'' click on ''Public Meetings at the FDA White Oak Campus.'' Please note that visitors to the White Oak Campus must enter through Building 1.

Contact Person: Stephanie L. Begansky, Center for Drug Evaluation and Research, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 31, Rm. 2417, Silver Spring, MD 20993–0002, 301–796–9001, FAX: 301–847–8533, email: *AAC@fda.hhs.gov,* or FDA Advisory Committee Information Line, 1–800–741–8138 (301–443–0572 in the Washington, DC area). A notice in the **Federal Register** about last minute modifications that impact a previously announced advisory committee meeting cannot always be published quickly enough to provide timely notice. Therefore, you should always check the Agency's Web site at *http://www.fda.gov/AdvisoryCommittees/default.htm* and scroll down to the appropriate advisory committee meeting link, or call the advisory committee information line to learn about possible modifications before coming to the meeting.

Agenda: The committees will discuss data and analyses published in 2006 or later that are relevant to further understanding the relationship between nonsteroidal anti-inflammatory drugs (NSAIDs) and cardiovascular thrombotic risk that is currently described in NSAID class labeling.

FDA intends to make background material available to the public no later than 2 business days before the meeting. If FDA is unable to post the background material on its Web site prior to the meeting, the background material will be made publicly available at the location of the advisory committee meeting, and the background material will be posted on FDA's Web site after the meeting. Background material is available at *http://www.fda.gov/AdvisoryCommittees/Calendar/default.htm.* Scroll down to the appropriate advisory committee meeting link.

Procedure: Interested persons may present data, information, or views, orally or in writing, on issues pending before the committee. Written submissions may be made to the contact person on or before January 27, 2014. Oral presentations from the public will be scheduled on February 11, 2014, between approximately 9 a.m. and 11 a.m. Those individuals interested in making formal oral presentations should notify the contact person and submit a brief statement of the general nature of the evidence or arguments they wish to present, the names and addresses of proposed participants, and an indication of the approximate time requested to make their presentation on or before January 16, 2014. Time allotted for each presentation may be limited. If the number of registrants requesting to speak is greater than can be reasonably accommodated during the scheduled open public hearing session, FDA may conduct a lottery to determine the speakers for the scheduled open public hearing session. The contact person will notify interested persons regarding their request to speak by January 17, 2014.

Persons attending FDA's advisory committee meetings are advised that the Agency is not responsible for providing access to electrical outlets.

FDA welcomes the attendance of the public at its advisory committee meetings and will make every effort to accommodate persons with physical disabilities or special needs. If you require special accommodations due to a disability, please contact Stephanie L. Begansky at least 7 days in advance of the meeting.

FDA is committed to the orderly conduct of its advisory committee meetings. Please visit our Web site at *http://www.fda.gov/AdvisoryCommittees/AboutAdvisoryCommittees/ucm111462.htm* for procedures on public conduct during advisory committee meetings.

Notice of this meeting is given under the Federal Advisory Committee Act (5 U.S.C. app. 2).

Dated: January 3, 2014.

Jill Hartzler Warner,

Acting Associate Commissioner for Special Medical Programs.

[FR Doc. 2014–00088 Filed 1–7–14; 8:45 am]

BILLING CODE 4160–01–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Docket ID: FEMA–2013–0050; OMB No. 1660–0025]

Agency Information Collection Activities: Proposed Collection; Comment Request

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: The Federal Emergency Management Agency, 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 a revision of a currently approved information collection. In accordance with the Paperwork Reduction Act of 1995, this notice seeks comments concerning FEMA grant administration forms used in disaster and non-disaster grant programs.

DATES: Comments must be submitted on or before March 10, 2014.

ADDRESSES: To avoid duplicate submissions to the docket, please use only one of the following means to submit comments:

(1) *Online.* Submit comments at *www.regulations.gov* under Docket ID FEMA–2013–0050. Follow the instructions for submitting comments.

(2) *Mail.* Submit written comments to Regulatory Affairs Division, Office of Chief Counsel, DHS/FEMA, 500 C Street SW., Room 8NE, Washington, DC 20472–3100.

(3) *Facsimile.* Submit comments to (703) 483–2999.

All submissions received must include the agency name and Docket ID. Regardless of the method used for submitting comments or material, all submissions will be posted, without change, to the Federal eRulemaking Portal at *http://www.regulations.gov,* and will include any personal information you provide. Therefore, submitting this information makes it public. You may wish to read the Privacy Act notice that is available via the link in the footer of *www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Pamela Greene, Assistance Officer, Protection and National Preparedness, Grant Program Directorate, (202) 786–9519. You may contact the Records Management Division for copies of the proposed collection of information at facsimile number (202) 646–3347 or

email address: *FEMA-Information-Collections-Management@dhs.gov.*

SUPPLEMENTARY INFORMATION:

Title 44 CFR, Part 13, Uniform Administrative Requirements for Grants and Cooperative Agreements to State and Local Government establishes uniform administrative rules for Federal grants and cooperative agreements and sub-awards to State, local and Indian tribal governments. FEMA, in coordination with the Department of Homeland Security (DHS), has determined that in order to have consistent implementation of FEMA grant administration policies and to minimize the administrative disruption for State and local partners, it is necessary to standardize FEMA grant administration forms used in FEMA grant programs. FEMA in close consultation with DHS Grants Policy and Oversight office will maintain its current grant forms. The forms are designed to collect information of an administrative or financial nature. Other supplementary grant program information used to determine issues related to eligibility and program management are collected separately with an approved OMB clearance.

OMB Circular A–133 requires recipients that expend a specified amount in a year in Federal funds must have an independent auditor perform a single or program-specific audit for that year. Executive Order 12372 established that States which have established a review and comment procedure be given opportunity to evaluate all applications submitted.

The American Recovery and Reinvestment Act of 2009, Public Law 111–5, was created to promote financial stimulus throughout the United States. Opportunities include funding for port security and bus and rail projects. Funds from this Act can be in the form of grant opportunities or outright purchases, depending upon the program and the funding allocation.

Collection of Information

Title: FEMA Grant Administration Forms/Non-Disaster (ND) Grants System.

Type of Information Collection: Revision of a currently approved information collection.

FEMA Forms: FEMA Form 112–02–1, Financial Status Report, FEMA Form 112–0–2, Budget Information-Construction; FEMA Form 112–0–3,A,B,C, Summary Sheet for Assurances and Certifications; FEMA Form 112–0–4, Outlay Report and Request for Reimbursement for Construction Program; FEMA Form 112–0–5, Report of Government Property; FEMA Form 112–0–6, Reconciliation of Grants and Cooperative Agreements; FEMA Form 112–0–7, Obligating Document for Award/Amendment; FEMA Form 112–0–8, Budget Information-Non-Construction; FEMA Form 112–0–9, Detailed Budget Worksheet; and FEMA Form 112–0–10, FEMA Grants Application Form.

Abstract: The information collection activity is the collection of financial and administrative information from States and local governments, universities, and non-profits pertaining to grant and cooperative agreement awards that include application, program narrative statement, grant award, performance information, outlay report, property management, and closeout information. The information submitted by grant recipients on forms allows FEMA to evaluate applications and make award decisions, monitor ongoing performance and manage the flow of federal funds, and to appropriately close-out grants or cooperative agreements, when all work is completed.

Affected Public: State, Local or Tribal Government; Business or Other for Profit; and Not-for-profit Institutions.

Number of Respondents: 56.

Number of Responses: 13,747.

Estimated Total Annual Burden Hours: 184,682.

Estimated Cost: There are no record keeping, capital, start-up or maintenance costs associated with this information collection.

Comments

Comments may be submitted as indicated in the **ADDRESSES** caption above. Comments are solicited to (a) evaluate whether the proposed data collection is necessary for the proper performance of the agency, including whether the information shall 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: December 20, 2013.

Charlene D. Myrthil,

Director, Records Management Division, Mission Support Bureau, Federal Emergency Management Agency, Department of Homeland Security.

[FR Doc. 2014–00062 Filed 1–7–14; 8:45 am]

BILLING CODE 9111–78–P

DEPARTMENT OF HOMELAND SECURITY

Federal Emergency Management Agency

[Internal Agency Docket No. FEMA–4159–DR; Docket ID FEMA–2013–0001]

Texas; Major Disaster and Related Determinations

AGENCY: Federal Emergency Management Agency, DHS.

ACTION: Notice.

SUMMARY: This is a notice of the Presidential declaration of a major disaster for the State of Texas (FEMA–4159–DR), dated December 20, 2013, and related determinations.

DATES: *Effective Date:* December 20, 2013.

FOR FURTHER INFORMATION CONTACT: Dean Webster, Office of Response and Recovery, Federal Emergency Management Agency, 500 C Street SW., Washington, DC 20472, (202) 646–2833.

SUPPLEMENTARY INFORMATION: Notice is hereby given that, in a letter dated December 20, 2013, the President issued a major disaster declaration under the authority of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 *et seq.* (the ''Stafford Act''), as follows:

I have determined that the damage in certain areas of the State of Texas resulting from severe storms and flooding during the period of October 30–31, 2013, is of sufficient severity and magnitude to warrant a major disaster declaration under the Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. 5121 et seq. (the ''Stafford Act''). Therefore, I declare that such a major disaster exists in the State of Texas.

In order to provide Federal assistance, you are hereby authorized to allocate from funds available for these purposes such amounts as you find necessary for Federal disaster assistance and administrative expenses.

You are authorized to provide Public Assistance in the designated areas and Hazard Mitigation throughout the State. Consistent with the requirement that Federal assistance be supplemental, any Federal funds provided under the Stafford Act for Hazard Mitigation will be limited to 75 percent of the total eligible costs. Federal funds provided under the Stafford Act for Public Assistance also will be limited to 75 percent of the total eligible costs, with the

exception of projects that meet the eligibility criteria for a higher Federal cost-sharing percentage under the Public Assistance Alternative Procedures Pilot Program for Debris Removal implemented pursuant to Section 428 of the Stafford Act.

Further, you are authorized to make changes to this declaration for the approved assistance to the extent allowable under the Stafford Act.

The Federal Emergency Management Agency (FEMA) hereby gives notice that pursuant to the authority vested in the Administrator, under Executive Order 12148, as amended, William J. Doran III, of FEMA is appointed to act as the Federal Coordinating Officer for this major disaster.

The following areas of the State of Texas have been designated as adversely affected by this major disaster:

Caldwell, Hays, and Travis Counties for Public Assistance.

All counties within the State of Texas are eligible to apply for assistance under the Hazard Mitigation Grant Program.

(The following Catalog of Federal Domestic Assistance Numbers (CFDA) are to be used for reporting and drawing funds: 97.030, Community Disaster Loans; 97.031, Cora Brown Fund; 97.032, Crisis Counseling; 97.033, Disaster Legal Services; 97.034, Disaster Unemployment Assistance (DUA); 97.046, Fire Management Assistance Grant; 97.048, Disaster Housing Assistance to Individuals and Households in Presidentially Declared Disaster Areas; 97.049, Presidentially Declared Disaster Assistance—Disaster Housing Operations for Individuals and Households; 97.050, Presidentially Declared Disaster Assistance to Individuals and Households—Other Needs; 97.036, Disaster Grants—Public Assistance (Presidentially Declared Disasters); 97.039, Hazard Mitigation Grant.)

W. Craig Fugate,

Administrator, Federal Emergency Management Agency.

[FR Doc. 2014–00064 Filed 1–7–14; 8:45 am]

BILLING CODE 9111–23–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

[Docket No. FWS–R2–ES–2013–0130]; [FXES11120200000F2–145–FF02ENEH00]

Notice of Availability: Low-Effect Screening Form and Proposed Bosque Canyon Ranch Low-Effect Habitat Conservation Plan, Bosque County, Texas

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of availability of the low-effect screening form supporting a categorical exclusion, draft low-effect habitat conservation plan, incidental take permit application, and request for comments.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), announce the availability of the low-effect screening form (LESF) under the National Environmental Policy Act (NEPA) of 1969, that supports a categorical exclusion for the draft Low-Effect Habitat Conservation Plan (dHCP), and the incidental take permit application for the Bosque Canyon Ranch in Bosque County, TX. The Bosque Canyon Ranch (Applicant), has applied for an incidental take permit (ITP) under Section 10(a)(1)(B) of the Endangered Species Act (Act) of 1973, as amended. The requested permit, which would be in effect for a period of 50 years, if granted, would authorize incidental take of the golden-cheeked warbler (*Setophaga chrysoparia*) resulting from residential development and operation of the property.

DATES: *Comments:* We will accept comments received or postmarked on or before February 7, 2014. Comments submitted electronically using the Federal e–Rulemaking Portal (see **ADDRESSES** section, below) must be received by 11:59 p.m. Eastern Time on the closing date. Any comments that we receive after the closing date may not be considered in the final decisions on these actions.

ADDRESSES: *Obtaining Documents:*

- *Internet:* You may obtain copies of the documents on the Internet at *http://www.regulations.gov* (Docket Number FWS–R2–ES–2013–0130), or on the Service's Web site at *http://www.fws.gov/southwest/es/ArlingtonTexas/.*
- *U.S. Mail:* Arlington, Texas, Ecological Services Field Office, 2005 NE. Green Oaks Blvd., Suite 140, TX 76006; telephone 817–277–1100. Please note that your request is in reference to the BCRHCP (TE–21506B).
- *In-Person:* Copies of the draft LESF and draft low-effect HCP are also available for public inspection and review at the following locations, by appointment and written request only, 8 a.m. to 4:30 p.m.:
  - Department of the Interior, Natural Resources Library, 1849 C. St. NW., Washington, DC 20240.
  - U.S. Fish and Wildlife Service, 500 Gold Avenue SW., Room 6034, Albuquerque, NM 87102.
  - U.S. Fish and Wildlife Service, 2005 NE. Green Oaks Blvd., Suite 140, TX 76006; calling 817–277–1100.; or faxing 817–277–1129.

Persons wishing to review the application may obtain a copy by writing to the Regional Director, U.S. Fish and Wildlife Service, P.O. Box 1306, Room 4012, Albuquerque, NM 87103, Attention: Branch Chief, Environmental Review.

Comment submission: You may submit written comments by one of the following methods:

- *Electronically:* Go to the Federal e–Rulemaking Portal: *http://www.regulations.gov.* In the Search box, enter FWS–R2–ES–2013–0130, which is the docket number for this notice. Then, on the left side of the screen, under the Document Type heading, click on the Notices link to locate this document and submit a comment.
- *By hard copy:* Submit by U.S. mail or hand-delivery to: Public Comments Processing, Attn: FWS–R2–ES–2013–0130; 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 by only the methods described above. We will post all information received 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: Debra Bills, Field Supervisor, U.S. Fish and Wildlife Service, 2005 NE. Green Oaks Blvd., Suite 140, TX 76006; or by telephone at 817–277–1100.

SUPPLEMENTARY INFORMATION: In accordance with the requirements of the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321 *et seq.*), we advise the public that:

1. We have gathered the information necessary to determine impacts related to potential issuance of an incidental take permit (ITP) and have determined the proposed action qualifies as a low-effect HCP and is categorically excluded from the NEPA process; and,

2. The applicant has developed and proposes to implement its dHCP, as part of the application for an ITP, which describes the measures the applicant has agreed to take to minimize and mitigate the effects of incidental take of golden-cheeked warblers to the maximum extent practicable pursuant to section 10(a)(1)(B) of the Endangered Species Act of 1973 (Act), as amended (16 U.S.C. 1531 *et seq.*).

The requested permit, which would be in effect for a period of 50 years, if granted, would authorize incidental take of the golden-cheeked warbler (*Setophaga chrysoparia*) (Covered Species) as a result of residential development and operation of the property. The proposed incidental take may occur on the Bosque Canyon Ranch, Bosque County, TX (Permit

Area), as a result of activities associated with the Applicant's operation and maintenance activities (Covered Activities). Such actions may require disturbance within potential golden-cheeked warbler habitat. The ranch has proposed to mitigate the 28.21 acres of direct impacts and 293.63 acres of indirect impacts to the golden-cheeked warbler onsite. A total of approximately 924.35 acres of suitable GCWA breeding habitat are present within two permanent conservation easements on the property with 770 of those acres neither directly nor indirectly affected by the proposed development. These habitat acres will be conserved in perpetuity and additional mitigation is proposed through the conservation of 227.6 acres of immature supporting habitat that will be managed to develop into suitable breeding habitat prior to the expiration of the permit.

Section 9 of the Act and its implementing regulations prohibit ''take'' of fish and wildlife species listed as threatened or endangered under section 4 of the Act. However, section 10(a) of the Act authorizes us to issue permits to take listed wildlife species where such take is incidental to, and not the purpose of, otherwise lawful activities and where the applicant meets certain statutory requirements.

Public Availability of Comments

Written comments we receive become part of the public record associated with this action. Before including your address, phone number, email address, or other personal identifying information in your comment, you should be aware that your entire comment—including your personal identifying information—may be made publicly available at any time. While you can request in your comment that we withhold your personal identifying information from public review, we cannot guarantee that we will be able to do so. We will not consider anonymous comments. All submissions from organizations or businesses, and from individuals identifying themselves as representatives or officials of organizations or businesses, will be made available for public disclosure in their entirety.

Authority

We provide this notice under section 10(c) of the Act (16 U.S.C. 1531 *et seq.*) and its implementing regulations (50 CFR 17.22) and NEPA (42 U.S.C. 4321 *et seq.*) and its implementing regulations (40 CFR 1506.6).

Dana Roth,

Acting Regional Director, Southwest Region, Albuquerque, New Mexico.

[FR Doc. 2014–00082 Filed 1–7–14; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–AKR–DENA–14293; PPAKDENAP0, PDMPSAS12.YP0000]

Notice of Renewal of the Denali National Park and Preserve Aircraft Overflights Advisory Council

AGENCY: National Park Service, Interior.

ACTION: Notice of renewal.

SUMMARY: The Secretary of the Interior is giving notice of the renewal of the Denali National Park and Preserve Aircraft Overflights Advisory Council. The Council provides advice and recommendations on mitigation of impacts from aircraft overflights at Denali National Park and Preserve.

FOR FURTHER INFORMATION CONTACT: Miriam Valentine, Chief of Planning and Environmental Compliance, Denali Park and Preserve, 240 W. 5th Avenue, Anchorage, Alaska 99501, (907) 733–9102.

SUPPLEMENTARY INFORMATION: The Denali National Park and Preserve Aircraft Overflights Advisory Council has been established in accordance with the Denali National Park and Preserve's *2006 Backcountry Management Plan and EIS.* The plan concluded that air travel is an important means of access for backcountry users, and that scenic air tours are an important means for other park visitors to access and enjoy Mount McKinley and adjoining scenic peaks and glaciers. However, the cumulative impact of these tours, plus the additional aircraft traffic, must be mitigated to protect park resource values and the quality of the visitor experience. The plan calls for an aircraft overflights advisory group that will develop voluntary measures for assuring the safety of passengers, pilots, and mountaineers, and for achieving standards that represent desired future resource conditions at Denali. The National Park Service needs the advice of this group to develop effective mitigation measures that will be acceptable to stakeholders. The Council is composed of individuals that represent a broad range of interests, including air taxi operators, commercial aviation, local landowners, the State of Alaska, the Federal Aviation Administration, climbers and other park users, and the environmental community.

Certification: I hereby certify that the renewal of the Denali National Park and Preserve Aircraft Overflights Advisory Council is necessary and in the public interest in connection with the performance of duties imposed on the Department of the Interior by the National Park Service Organic Act, 16 U.S.C. 1–4, and other statutes relating to the administration of the National Park System.

Dated: December 11, 2013.

Sally Jewell,

Secretary of the Interior.

[FR Doc. 2014–00081 Filed 1–7–14; 8:45 am]

BILLING CODE 4312–EF–P

INTERNATIONAL TRADE COMMISSION

[Investigation Nos. 701–TA–511 and 731–TA–1246–1247 (Preliminary)]

Certain Crystalline Silicon Photovoltaic Products From China and Taiwan; Institution of Antidumping and Countervailing Duty Investigations and Scheduling of Preliminary Phase Investigations

AGENCY: United States International Trade Commission.

ACTION: Notice.

SUMMARY: The Commission hereby gives notice of the institution of investigations and commencement of preliminary phase antidumping and countervailing duty investigations Nos. 701–TA–511 and 731–TA–1246–1247 (Preliminary) under sections 703(a) and 733(a) of the Tariff Act of 1930 (19 U.S.C. 1671b(a) and 1673b(a)) (the Act) to determine whether there is a reasonable indication that 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 imports from China and Taiwan of certain crystalline silicon photovoltaic products, provided for in subheading 8541.40.60 (statistical reporting numbers 8541.40.60.20 or 8541.40.60.30 of the Harmonized Tariff Schedule of the United States, that are alleged to be sold in the United States at less than fair value and alleged to be subsidized by the Government of China. Unless the Department of Commerce extends the time for initiation pursuant to sections 702(c)(1)(B) or 732(c)(1)(B) of the Act (19 U.S.C. 1671a(c)(1)(B) or 1673a(c)(1)(B)), the Commission must

reach a preliminary determination in antidumping and countervailing duty investigations in 45 days, or in this case by February 14, 2014. The Commission's views must be transmitted to Commerce within five business days thereafter, or by February 24, 2014.

DATES: Effective December 31, 2013.

FOR FURTHER INFORMATION CONTACT: Chris Cassise (202–708–5408), 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 these investigations may be viewed on the Commission's electronic docket (EDIS) at *http://edis.usitc.gov.*

SUPPLEMENTARY INFORMATION: For further information concerning the conduct of these investigations 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 B (19 CFR part 207).

Background.—These investigations are being instituted in response to a petition filed on December 31, 2013, by SolarWorld America Industries, Inc., Hillsboro, OR.

Participation in the investigations and public service list.—Persons (other than petitioners) wishing to participate in the investigations as parties must file an entry of appearance with the Secretary to the Commission, as provided in sections 201.11 and 207.10 of the Commission's rules, not later than seven days after publication of this notice in the **Federal Register**. Industrial users and (if the merchandise under investigation is sold at the retail level) representative consumer organizations have the right to appear as parties in Commission antidumping and countervailing duty investigations. The Secretary will prepare a public service list containing the names and addresses of all persons, or their representatives, who are parties to these investigations upon the expiration of the period for filing entries of appearance.

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 these investigations available to authorized applicants representing interested parties (as defined in 19 U.S.C. 1677(9)) who are parties to the investigations under the APO issued in the investigations, provided that the application is made not later than seven days after the publication of this notice in the **Federal Register**. A separate service list will be maintained by the Secretary for those parties authorized to receive BPI under the APO.

Conference.—The Commission's Director of Investigations has scheduled a conference in connection with these investigations for 9:30 a.m. on January 21, 2014, at the U.S. International Trade Commission Building, 500 E Street SW., Washington, DC. Requests to appear at the conference should be emailed to *William.bishop@usitc.gov* and *Sharon.bellamy@usitc.gov* (DO NOT FILE ON EDIS) on or before January 16, 2014. Parties in support of the imposition of countervailing and antidumping duties in these investigations and parties in opposition to the imposition of such duties will each be collectively allocated one hour within which to make an oral presentation at the conference. A nonparty who has testimony that may aid the Commission's deliberations may request permission to present a short statement at the conference.

Written submissions.—As provided in sections 201.8 and 207.15 of the Commission's rules, any person may submit to the Commission on or before January 24, 2014, a written brief containing information and arguments pertinent to the subject matter of the investigations. Parties may file written testimony in connection with their presentation at the conference no later than three days before the conference. If briefs or written testimony contain BPI, they must conform with the requirements of sections 201.6, 207.3, and 207.7 of the Commission's rules. Please consult the Commission's rules, as amended, 76 FR 61937 (Oct. 6, 2011) and the Commission's Handbook on Filing Procedures, 76 FR 62092 (Oct. 6, 2011), 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 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 207.12 of the Commission's rules.

Issued: January 3, 2014.

By order of the Commission.

William R. Bishop,

Supervisory Hearings and Information Officer.

[FR Doc. 2014–00130 Filed 1–7–14; 8:45 am]

BILLING CODE 7020–02–P

JUDICIAL CONFERENCE OF THE UNITED STATES

Hearings of the Judicial Conference Advisory Committee on Rules of Bankruptcy Procedure; *Federal Register* Citation of Previous Announcement: 78 FR 49768.

AGENCY: Judicial Conference of the United States, Advisory Committee on Rules of Bankruptcy Procedure.

ACTION: Notice of Cancellation of Open Hearing.

SUMMARY: The following public hearing on proposed amendments to the Federal Rules of Bankruptcy Procedure has been canceled: Bankruptcy Rules Hearing, January 31, 2014, Washington, DC

FOR FURTHER INFORMATION CONTACT: Jonathan C. Rose, Secretary and Chief Rules Officer, Rules Committee Support Office, Administrative Office of the United States Courts, Washington, DC 20544, telephone (202) 502–1820.

Dated: January 3, 2014.

Jonathan C. Rose,

Secretary and Chief Rules Officer.

[FR Doc. 2014–00112 Filed 1–7–14; 8:45 am]

BILLING CODE 2210–55–P

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

Importer of Controlled Substances; Notice of Registration; Cerilliant Corporation

By Notice dated September 9, 2013, and published in the **Federal Register** on September 17, 2013, 78 FR 57176, Cerilliant Corporation, 811 Paloma Drive, Suite A, Round Rock, Texas 78665–2402, made application by renewal to the Drug Enforcement Administration (DEA) to be registered as an importer of the following basic classes of controlled substances:

Drug	Schedule
Cathinone (1235)	I

Drug	Schedule
Methcathinone (1237)	I
Mephedrone (1248)	I
N-Ethylamphetamine (1475)	I
N,N-Dimethylamphetamine (1480)	I
Fenethylline (1503)	I
Gamma Hydroxybutyric Acid (2010).	I
JWH-018 (7118)	I
JWH-073 (7173)	I
JWH-200 (7200)	I
Alpha-ethyltryptamine (7249)	I
Ibogaine (7260)	I
CP-47497 (7297)	I
CP-47497 C8 Homologue (7298)	I
Lysergic acid diethylamide (7315)	I
2C-T-7 (7348)	I
Marihuana (7360)	I
Tetrahydrocannabinols (7370)	I
Mescaline (7381)	I
3,4,5-Trimethoxyamphetamine (7390).	I
4-Bromo-2,5-dimethoxyamphetamine (7391).	I
4-Bromo-2,5-dimethoxyphenethylamine (7392).	I
4-Methyl-2,5-dimethoxyamphetamine (7395).	I
2,5-Dimethoxyamphetamine (7396).	I
3,4-Methylenedioxyamphetamine (7400).	I
3,4-Methylenedioxy-N-ethylamphetamine (7404).	I
3,4-Methylenedioxymethamphetamine (7405).	I
4-Methoxyamphetamine (7411)	I
5-Methoxy-N-N-dimethyltryptamine (7431).	I
Alpha-methyltryptamine (7432)	I
Diethyltryptamine (7434)	I
Dimethyltryptamine (7435)	I
Psilocybin (7437)	I
Psilocyn (7438)	I
5-Methoxy-N,N-diisopropyltryptamine (7439).	I
N-Benzylpiperazine (7493)	I
MDPV (7535)	I
Methylone (7540)	I
Desomorphine (9055)	I
Etorphine (except HCl)(9056)	I
Heroin (9200)	I
Morphine-N-oxide (9307)	I
Normorphine (9313)	I
Pholcodine (9314)	I
Dextromoramide (9613)	I
Dipipanone (9622)	I
Racemoramide (9645)	I
Trimeperidine (9646)	I
1-Methyl-4-phenyl-4-propionoxypiperidine (9661).	I
Tilidine (9750)	I
Amphetamine (1100)	II
Methamphetamine (1105)	II
Methylphenidate (1724)	II
Amobarbital (2125)	II
Pentobarbital (2270)	II
Secobarbital (2315)	II
Phencyclidine (7471)	II
Phenylacetone (8501)	II
Cocaine (9041)	II
Codeine (9050)	II
Dihydrocodeine (9120)	II
Oxycodone (9143)	II
Hydromorphone (9150)	II
Ecgonine (9180)	II
Ethylmorphine (9190)	II
Meperidine (9230)	II
Methadone (9250)	II
Dextropropoxyphene, bulk (9273)	II
Morphine (9300)	II
Oripavine (9330)	II
Thebaine (9333)	II
Levo-alphacetylmethadol (9648)	II
Oxymorphone (9652)	II
Poppy Straw Concentrate (9670)	II
Alfentanil (9737)	II
Sufentanil (9740)	II
Fentanyl (9801)	II

The company plans to import small quantities of the listed controlled substances for the manufacture of analytical reference standards.

In reference to drug codes 7360 and 7370, the company plans to import a synthetic cannabidiol and a synthetic tetrahydrocannabinol. No other activities for these drug codes are authorized for this registration.

Comments and requests for hearings on applications to import narcotic raw material are not appropriate. 72 FR 3417(2007)

DEA has considered the factors in 21 U.S.C. 823(a) and 952(a) and determined that the registration of Cerilliant Corporation to import the basic classes of controlled substances is consistent with the public interest and with United States obligations under international treaties, conventions, or protocols in effect on May 1, 1971. DEA has investigated Cerilliant Corporation to ensure that the company's registration is consistent with the public interest. The investigation has included inspection and testing of the company's physical security systems, verification of the company's compliance with state and local laws, and a review of the company's background and history. Therefore, pursuant to 21 U.S.C. 952(a) and 958(a), and in accordance with 21 CFR 1301.34, the above named company is granted registration as an importer of the basic classes of controlled substances listed.

Dated: December 23, 2013.

Joseph T. Rannazzisi,

Deputy Assistant Administrator, Office of Diversion Control, Drug Enforcement Administration.

[FR Doc. 2014–00057 Filed 1–7–14; 8:45 am]

BILLING CODE 4410–09–P

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

Manufacturer of Controlled Substances; Notice of Application; Noramco, Inc. (GA)

Pursuant to 21 CFR 1301.33(a), this is notice that on July 4, 2013, Noramco, Inc., 1440 Olympic Drive, Athens, Georgia 30601, made application by renewal to the Drug Enforcement Administration (DEA) to be registered as a bulk manufacturer of the following basic classes of controlled substances:

Drug	Schedule
Gamma Hydroxybutyric Acid (2010).	I
Dihydromorphine (9145)	I
Morphine-N-oxide (9307)	I
Codeine-N-oxide (9053)	I
Amphetamine (1100)	II
Methylphenidate (1724)	II
Codeine (9050)	II
Dihydrocodeine (9120)	II
Oxycodone (9143)	II
Hydromorphone (9150)	II
Hydrocodone (9193)	II
Morphine (9300)	II
Oripavine (9330)	II
Thebaine (9333)	II
Opium tincture (9630)	II
Oxymorphone (9652)	II
Noroxymorphone (9668)	II
Alfentanil (9737)	II
Remifentanil (9739)	II
Sufentanil (9740)	II
Carfentanil (9743)	II
Tapentadol (9780)	II
Fentanyl (9801)	II

The company plans to manufacture the listed controlled substances in bulk for distribution to its customers.

Any other such applicant, and any person who is presently registered with DEA to manufacture such substance, may file comments or objections to the issuance of the proposed registration pursuant to 21 CFR 1301.33(a).

Any such written comments or objections should be addressed, in quintuplicate, to the Drug Enforcement Administrator, Office of Diversion Control, Federal Register Representative (ODW), 8701 Morrissette Drive, Springfield, Virginia 22152; and must be filed no later than March 10, 2014.

Dated: December 23, 2013.

Joseph T. Rannazzisi,

Deputy Assistant Administrator, Office of Diversion Control, Drug Enforcement Administration.

[FR Doc. 2014–00054 Filed 1–7–14; 8:45 am]

BILLING CODE 4410–09–P

DEPARTMENT OF JUSTICE

Drug Enforcement Administration

Manufacturer of Controlled Substances; Notice of Application; Siegfried (USA), LLC

Pursuant to 21 CFR 1301.33(a), this is notice that on November 13, 2013, Siegfried (USA), LLC, 33 Industrial Park Road, Pennsville, New Jersey 08070, made application by renewal to the Drug Enforcement Administration (DEA) to be registered as a bulk manufacturer of the following basic classes of controlled substances:

Drug	Schedule
Gamma Hydroxybutyric Acid (2010).	I
Dihydromorphine (9145)	I
Hydromorphinol (9301)	I
Methylphenidate (1724)	II
Amobarbital (2125)	II
Pentobarbital (2270)	II
Secobarbital (2315)	II
Codeine (9050)	II
Oxycodone (9143)	II
Hydromorphone (9150)	II
Hydrocodone (9193)	II
Methadone (9250)	II
Methadone intermediate (9254)	II
Dextropropoxyphene, bulk (9273)	II
Morphine (9300)	II
Oripavine (9330)	II
Thebaine (9333)	II
Opium tincture (9630)	II
Oxymorphone (9652)	II

The company plans to manufacture the listed controlled substances in bulk for distribution to its customers.

Any other such applicant, and any person who is presently registered with DEA to manufacture such substance, may file comments or objections to the issuance of the proposed registration pursuant to 21 CFR 1301.33(a).

Any such written comments or objections should be addressed, in quintuplicate, to the Drug Enforcement Administration, Office of Diversion Control, Federal Register Representative (ODW), 8701 Morrissette Drive, Springfield, Virginia 22152; and must be filed no later than March 10, 2014.

Dated: December 23, 2013.

Joseph T. Rannazzisi,

Deputy Assistant Administrator, Office of Diversion Control, Drug Enforcement Administration.

[FR Doc. 2014–00053 Filed 1–7–14; 8:45 am]

BILLING CODE 4410–09–P

DEPARTMENT OF JUSTICE

Parole Commission

Sunshine Act Meeting

TIME AND DATE: 12:00 p.m., Tuesday, January 14, 2014.

PLACE: U.S. Parole Commission, 90 K Street NE., 3rd Floor, Washington, DC

STATUS: Closed.

MATTERS TO BE CONSIDERED: Determination on four original jurisdiction cases.

CONTACT PERSON FOR MORE INFORMATION: Patricia W. Moore, Staff Assistant to the Chairman, U.S. Parole Commission, 90 K Street NE., 3rd Floor, Washington, DC 20530, (202) 346–7001.

Dated: January 6, 2014.

J. Patricia W. Smoot,

Acting General Counsel, U.S. Parole Commission.

[FR Doc. 2014–00168 Filed 1–6–14; 4:15 pm]

BILLING CODE 4410–31–P

DEPARTMENT OF JUSTICE

Parole Commission

Sunshine Act Meeting

TIME AND DATE: 10:00 a.m., Tuesday, January 14, 2014.

PLACE: U.S. Parole Commission, 90 K Street NE., 3rd Floor, Washington, DC

STATUS: Open.

MATTERS TO BE CONSIDERED: Approval of August 8, 2013 minutes; reports from the Chairman, the Commissioners, and senior staff; Short Intervention For Success Program; Proposed Rulemaking Revising Conditions of Release update.

CONTACT PERSON FOR MORE INFORMATION: Patricia W. Moore, Staff Assistant to the Chairman, U.S. Parole Commission, 90 K Street NE., 3rd Floor, Washington, DC 20530, (202) 346–7001.

Dated: January 6, 2014.

J. Patricia W. Smoot,

Acting General Counsel, U.S. Parole Commission.

[FR Doc. 2014–00167 Filed 1–6–14; 4:15 pm]

BILLING CODE 4410–31–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 72–1045; EA–13–237; NRC–2013–0292]

In the Matter of Ameren Missouri, Callaway Plant; Independent Spent Fuel Storage Installation; Order Modifying License (Effective Immediately)

AGENCY: Nuclear Regulatory Commission.

ACTION: Order; modification.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) has issued a general license to Ameren Missouri (AmerenUE), authorizing the operation of an Independent Spent Fuel Storage Installation (ISFSI), in accordance with its regulations. This Order is being issued to AmerenUE because AmerenUE has identified near-term plans to store spent fuel in an ISFSI under the general license provisions of the NRC's regulations.

ADDRESSES: Please refer to Docket ID NRC–2013–0292 when contacting the NRC about the availability of information regarding this document. You may access publicly-available information related to this action by the following methods:

- *Federal Rulemaking Web site:* Go to *http://www.regulations.gov* and search for Docket ID NRC–2013–0292. 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 access publicly available documents online in the NRC Library 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: L. Raynard Wharton, Office of Nuclear

Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; telephone: 301–287–9196; email: *Raynard.Wharton@nrc.gov.*

SUPPLEMENTARY INFORMATION:

I. Introduction

Pursuant to § 2.106 of Title 10 of the *Code of Federal Regulations* (10 CFR), the NRC is providing notice, in the matter of Callaway Plant Independent Spent Fuel Storage Installation (ISFSI) Order Modifying License (Effective Immediately).

II. Further Information

I.

The NRC has issued a general license to Ameren Missouri (AmerenUE), authorizing the operation of an ISFSI, in accordance with the Atomic Energy Act of 1954, as amended, and Part 72 of Title 10 of the *Code of Federal Regulations* (10 CFR). This Order is being issued to AmerenUE because AmerenUE has identified near-term plans to store spent fuel in an ISFSI under the general license provisions of 10 CFR Part 72. The Commission's regulations at 10 CFR 72.212(b)(5), 10 CFR 50.54(p)(1), and 10 CFR 73.55(c)(5) require licensees to maintain safeguards contingency plan procedures to respond to threats of radiological sabotage and to protect the spent fuel against the threat of radiological sabotage, in accordance with 10 CFR part 73, Appendix C. Specific physical security requirements are contained in 10 CFR 73.51 or 73.55, as applicable.

Inasmuch as an insider has an opportunity equal to, or greater than, any other person, to commit radiological sabotage, the Commission has determined these measures to be prudent. Comparable Orders have been issued to all licensees that currently store spent fuel or have identified near-term plans to store spent fuel in an ISFSI.

II.

On September 11, 2001, terrorists simultaneously attacked targets in New York, NY, and near Washington, DC, using large commercial aircraft as weapons. In response to the attacks and intelligence information subsequently obtained, the Commission issued a number of Safeguards and Threat Advisories to its licensees to strengthen licensees' capabilities and readiness to respond to a potential attack on a nuclear facility. On October 16, 2002, the Commission issued Orders to the licensees of operating ISFSIs, to place the actions taken in response to the Advisories into the established regulatory framework and to implement additional security enhancements that emerged from NRC's ongoing comprehensive review. The Commission has also communicated with other Federal, State, and local government agencies and industry representatives to discuss and evaluate the current threat environment in order to assess the adequacy of security measures at licensed facilities. In addition, the Commission has conducted a comprehensive review of its safeguards and security programs and requirements.

As a result of its consideration of current safeguards and security requirements, as well as a review of information provided by the intelligence community, the Commission has determined that certain additional security measures (ASMs) are required to address the current threat environment, in a consistent manner throughout the nuclear ISFSI community. Therefore, the Commission is imposing requirements, as set forth in Attachments 1 and 2 of this Order, on all licensees of these facilities. These requirements, which supplement existing regulatory requirements, will provide the Commission with reasonable assurance that the public health and safety, the environment, and common defense and security continue to be adequately protected in the current threat environment. These requirements will remain in effect until the Commission determines otherwise.

The Commission recognizes that licensees may have already initiated many of the measures set forth in Attachments 1 and 2 to this Order, in response to previously issued Advisories, or on their own. It also recognizes that some measures may not be possible or necessary at some sites, or may need to be tailored to accommodate the specific circumstances existing at AmerenUE's facility, to achieve the intended objectives and avoid any unforeseen effect on the safe storage of spent fuel.

Although the ASMs implemented by licensees in response to the Safeguards and Threat Advisories have been sufficient to provide reasonable assurance of adequate protection of public health and safety, in light of the continuing threat environment, the Commission concludes that these actions should be embodied in an Order, consistent with the established regulatory framework.

To provide assurance that licensees are implementing prudent measures to achieve a consistent level of protection to address the current threat environment, licenses issued pursuant to 10 CFR 72.210 shall be modified to include the requirements identified in Attachments 1 and 2 to this Order. In addition, pursuant to 10 CFR 2.202, I find that, in light of the common defense and security circumstances described above, the public health, safety, and interest require that this Order be effective immediately.

III.

Accordingly, pursuant to Sections 53, 103, 104, 147, 149, 161b, 161i, 161o, 182, and 186 of the Atomic Energy Act of 1954, as amended, and the Commission's regulations in 10 CFR 2.202 and 10 CFR Parts 50, 72, and 73, *it is hereby ordered, effective immediately, that your general license is modified as follows:*

A. AmerenUE shall comply with the requirements described in Attachments 1 and 2 to this Order, except to the extent that a more stringent requirement is set forth in the Callaway Plant's physical security plan. AmerenUE shall demonstrate its ability to comply with the requirements in Attachments 1 and 2 to the Order no later than 365 days from the date of this Order or 90 days before the first day that spent fuel is initially placed in the ISFSI, whichever is earlier. AmerenUE must implement these requirements before initially placing spent fuel in the ISFSI. Additionally, AmerenUE must receive written verification from the NRC (Office of Nuclear Material Safety and Safeguards) that it has adequately demonstrated compliance with these requirements before initially placing spent fuel in the ISFSI.

B. 1. AmerenUE shall, within twenty (20) days of the date of this Order, notify the Commission: (1) If it is unable to comply with any of the requirements described in Attachments 1 and 2; (2) if compliance with any of the requirements is unnecessary, in its specific circumstances; or (3) if implementation of any of the requirements would cause AmerenUE to be in violation of the provisions of any Commission regulation or the facility license. The notification shall provide AmerenUE's justification for seeking relief from, or variation of, any specific requirement.

2. If AmerenUE considers that implementation of any of the requirements described in Attachments 1 and 2 to this Order would adversely impact the safe storage of spent fuel, AmerenUE must notify the Commission, within twenty (20) days of this Order, of the adverse safety impact, the basis for its determination that the requirement has an adverse safety impact, and either

a proposal for achieving the same objectives specified in Attachments 1 and 2 requirements in question, or a schedule for modifying the facility, to address the adverse safety condition. If neither approach is appropriate, AmerenUE must supplement its response, to Condition B.1 of this Order, to identify the condition as a requirement with which it cannot comply, with attendant justifications, as required under Condition B.1.

C. 1. AmerenUE shall, within twenty (20) days of this Order, submit to the Commission, a schedule for achieving compliance with each requirement described in Attachments 1 and 2.

2. AmerenUE shall report to the Commission when it has achieved full compliance with the requirements described in Attachments 1 and 2.

D. All measures implemented or actions taken in response to this Order shall be maintained until the Commission determines otherwise.

AmerenUE's response to Conditions B.1, B.2, C.1, and C.2, above, shall be submitted in accordance with 10 CFR 72.4. In addition, submittals and documents produced by AmerenUE as a result of this Order, that contain Safeguards Information as defined by 10 CFR 73.22, shall be properly marked and handled, in accordance with 10 CFR 73.21 and 73.22.

The Director, Office of Nuclear Material Safety and Safeguards, may, in writing, relax or rescind any of the above conditions, for good cause.

IV.

In accordance with 10 CFR 2.202, AmerenUE must, and any other person adversely affected by this Order may, submit an answer to this Order within 20 days of its publication in the **Federal Register.** In addition, AmerenUE and any other person adversely affected by this Order may request a hearing on this Order within 20 days of its publication in the **Federal Register.** Where good cause is shown, consideration will be given to extending the time to answer or request a hearing. A request for extension of time must be made, in writing, to the Director, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, and include a statement of good cause for the extension.

The answer may consent to this Order. If the answer includes a request for a hearing, it shall, under oath or affirmation, specifically set forth the matters of fact and law on which AmerenUE relies and the reasons as to why the Order should not have been issued. If a person other than AmerenUE requests a hearing, that person shall set forth with particularity the manner in which his/her interest is adversely affected by this Order and shall address the criteria set forth in 10 CFR 2.309(d).

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 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 electronically, 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 request or petition for hearing (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 NRC's public Web site at *http://www.nrc.gov/site-help/e-submittals/apply-certificates.html.* System requirements for accessing the E-Submittal server are detailed in 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 agency'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 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 of the Commission, 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 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. 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.

If a hearing is requested by AmerenUE or a person whose interest is adversely affected, the Commission will issue an Order designating the time and place of any hearing. If a hearing is held, the issue to be considered at such hearing shall be whether this Order should be sustained.

Pursuant to 10 CFR 2.202(c)(2)(i), AmerenUE may, in addition to requesting a hearing, at the time the answer is filed or sooner, move the presiding officer to set aside the immediate effectiveness of the Order on the grounds that the Order, including the need for immediate effectiveness, is not based on adequate evidence, but on mere suspicion, unfounded allegations, or error.

In the absence of any request for hearing, or written approval of an extension of time in which to request a hearing, the provisions as specified in Section III shall be final twenty (20) days from the date this Order is published in the **Federal Register**, without further Order or proceedings. If an extension of time for requesting a hearing has been approved, the provisions as specified in Section III, shall be final when the extension expires, if a hearing request has not been received. *An answer or a request for hearing shall not stay the immediate effectiveness of this order.*

Dated at Rockville, Maryland, this 30th day of December, 2013.

For the nuclear regulatory commission.

Keith McConnell,

Acting Director, Office of Nuclear Material Safety and Safeguards.

Attachment 1—Additional Security Measures (ASMs) for Physical Protection of Dry Independent Spent Fuel Storage Installations (ISFSIs) Contains Safeguards Information and is not Included in the Federal Register Notice

Attachment 2—Additional Security Measures for Access Authorization and Fingerprinting at Independent Spent Fuel Storage Installations, dated June 14, 2013

A. General Basis Criteria

1. These additional security measures (ASMs) are established to delineate an independent spent fuel storage installation (ISFSI) licensee's responsibility to enhance security measures related to authorization for unescorted access to the protected area of an ISFSI in response to the current threat environment.

2. Licensees whose ISFSI is collocated with a power reactor may choose to comply with the U.S. Nuclear Regulatory Commission (NRC)-approved reactor access authorization program for the associated reactor as an alternative means to satisfy the provisions of sections B through G below. Otherwise, licensees shall comply with the access authorization and fingerprinting requirements of section B through G of these ASMs.

3. Licensees shall clearly distinguish in their 20-day response which method they intend to use in order to comply with these ASMs.

B. Additional Security Measures for Access Authorization Program

1. The licensee shall develop, implement and maintain a program, or enhance its existing program, designed to ensure that persons granted unescorted access to the protected area of an ISFSI are trustworthy and reliable and do not constitute an unreasonable risk to the public health and safety for the common defense and security, including a potential to commit radiological sabotage.

a. To establish trustworthiness and reliability, the licensee shall develop, implement, and maintain procedures for conducting and completing background investigations, prior to granting access. The scope of background investigations must address at least the past three years and, as a minimum, must include:

i. Fingerprinting and a Federal Bureau of Investigation (FBI) identification and criminal history records check (CHRC). Where an applicant for unescorted access has been previously fingerprinted with a favorably completed CHRC, (such as a CHRC pursuant to compliance with orders for access to safeguards information) the licensee may accept the results of that CHRC, and need not submit another set of fingerprints, provided the CHRC was completed not more than three years from the date of the application for unescorted access.

ii. Verification of employment with each previous employer for the most recent year from the date of application.

iii. Verification of employment with an employer of the longest duration during any calendar month for the remaining next most recent two years.

iv. A full credit history review.

v. An interview with not less than two character references, developed by the investigator.

vi. A review of official identification (e.g., driver's license; passport; government identification; state-, province-, or country-of-birth issued certificate of birth) to allow comparison of personal information data provided by the applicant. The licensee shall maintain a photocopy of the identifying document(s) on file, in accordance with ''Protection of Information,'' in Section G of these ASMs.

vii. Licensees shall confirm eligibility for employment through the regulations of the U.S. Department of Homeland Security, U.S. Citizenship and Immigration Services, and shall verify and ensure, to the extent possible, the accuracy of the provided social security number and alien registration number, as applicable.

b. The procedures developed or enhanced shall include measures for

confirming the term, duration, and character of military service for the past 3 years, and/or academic enrollment and attendance in lieu of employment, for the past 5 years.

c. Licensees need not conduct an independent investigation for individuals employed at a facility who possess active ''Q'' or ''L'' clearances or possess another active U.S. Government-granted security clearance (*i.e.,* Top Secret, Secret, or Confidential).

d. A review of the applicant's criminal history, obtained from local criminal justice resources, may be included in addition to the FBI CHRC, and is encouraged if the results of the FBI CHRC, employment check, or credit check disclose derogatory information. The scope of the applicant's local criminal history check shall cover all residences of record for the past three years from the date of the application for unescorted access.

2. The licensee shall use any information obtained as part of a CHRC solely for the purpose of determining an individual's suitability for unescorted access to the protected area of an ISFSI.

3. The licensee shall document the basis for its determination for granting or denying access to the protected area of an ISFSI.

4. The licensee shall develop, implement, and maintain procedures for updating background investigations for persons who are applying for reinstatement of unescorted access. Licensees need not conduct an independent reinvestigation for individuals who possess active ''Q'' or ''L'' clearances or possess another active U.S. Government granted security clearance, i.e., Top Secret, Secret or Confidential.

5. The licensee shall develop, implement, and maintain procedures for reinvestigations of persons granted unescorted access, at intervals not to exceed 5 years. Licensees need not conduct an independent reinvestigation for individuals employed at a facility who possess active ''Q'' or ''L'' clearances or possess another active U.S. Government granted security clearance, i.e., Top Secret, Secret or Confidential.

6. The licensee shall develop, implement, and maintain procedures designed to ensure that persons who have been denied unescorted access authorization to the facility are not allowed access to the facility, even under escort.

7. The licensee shall develop, implement, and maintain an audit program for licensee and contractor/vendor access authorization programs that evaluate all program elements and include a person knowledgeable and practiced in access authorization program performance objectives to assist in the overall assessment of the site's program effectiveness.

C. Fingerprinting Program Requirements

1. In a letter to the NRC, the licensee must nominate an individual who will review the results of the FBI CHRCs to make trustworthiness and reliability determinations for unescorted access to an ISFSI. This individual, referred to as the ''reviewing official,'' must be someone who requires unescorted access to the ISFSI. The NRC will review the CHRC of any individual nominated to perform the reviewing official function. Based on the results of the CHRC, the NRC staff will determine whether this individual may have access. If the NRC determines that the nominee may not be granted such access, that individual will be prohibited from obtaining access.[1] Once the NRC approves a reviewing official, the reviewing official is the only individual permitted to make access determinations for other individuals who have been identified by the licensee as having the need for unescorted access to the ISFSI, and have been fingerprinted and have had a CHRC in accordance with these ASMs. The reviewing official can only make access determinations for other individuals, and therefore cannot approve other individuals to act as reviewing officials. Only the NRC can approve a reviewing official. Therefore, if the licensee wishes to have a new or additional reviewing official, the NRC must approve that individual before he or she can act in the capacity of a reviewing official.

2. No person may have access to Safeguards Information (SGI) or unescorted access to any facility subject to NRC regulation, if the NRC has determined, in accordance with its administrative review process based on fingerprinting and an FBI identification and CHRC, that the person may not have access to SGI or unescorted access to any facility subject to NRC regulation.

3. All fingerprints obtained by the licensee under this Order, must be submitted to the Commission for transmission to the FBI.

4. The licensee shall notify each affected individual that the fingerprints will be used to conduct a review of his/her criminal history record and inform the individual of the procedures for revising the record or including an explanation in the record, as specified in the ''Right to Correct and Complete Information,'' in section F of these ASMs.

5. Fingerprints need not be taken if the employed individual (e.g., a licensee employee, contractor, manufacturer, or supplier) is relieved from the fingerprinting requirement by 10 CFR 73.61, has a favorably adjudicated U.S. Government CHRC within the last 5 years, or has an active Federal security clearance. Written confirmation from the Agency/employer who granted the Federal security clearance or reviewed the CHRC must be provided to the licensee. The licensee must retain this documentation for a period of three years from the date the individual no longer requires access to the facility.

D. Prohibitions

1. A licensee shall not base a final determination to deny an individual unescorted access to the protected area of an ISFSI solely on the basis of information received from the FBI involving: an arrest more than 1 year old for which there is no information of the disposition of the case, or an arrest that resulted in dismissal of the charge, or an acquittal.

2. A licensee shall not use information received from a CHRC obtained pursuant to this Order in a manner that would infringe upon the rights of any individual under the First Amendment to the Constitution of the United States, nor shall the licensee use the information in any way that would discriminate among individuals on the basis of race, religion, national origin, sex, or age.

E. Procedures for Processing Fingerprint Checks

1. For the purpose of complying with this Order, licensees shall, using an appropriate method listed in 10 CFR 73.4, submit to the NRC's Division of Facilities and Security, Mail Stop T–03B46M, one completed, legible standard fingerprint card (Form FD–258, ORIMDNRCOOOZ) or, where practicable, other fingerprint records for each individual seeking unescorted access to an ISFSI, to the Director of the Division of Facilities and Security, marked for the attention of the Division's Criminal History Check Section. Copies of these forms may be obtained by writing the Office of Information Services, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, by calling 301–415–5877, or by email to *forms@nrc.gov.* Practicable alternative formats are set

[1] The NRC's determination of this individual's unescorted access to the ISFSI, in accordance with the process, is an administrative determination that is outside the scope of the Order.

forth in 10 CFR 73.4. The licensee shall establish procedures to ensure that the quality of the fingerprints taken results in minimizing the rejection rate of fingerprint cards because of illegible or incomplete cards.

2. The NRC will review submitted fingerprint cards for completeness. Any Form FD–258 fingerprint record containing omissions or evident errors will be returned to the licensee for corrections. The fee for processing fingerprint checks includes one re-submission if the initial submission is returned by the FBI because the fingerprint impressions cannot be classified. The one free re-submission must have the FBI Transaction Control Number reflected on the re-submission. If additional submissions are necessary, they will be treated as initial submittals and will require a second payment of the processing fee.

3. Fees for processing fingerprint checks are due upon application. The licensee shall submit payment of the processing fees electronically. To be able to submit secure electronic payments, licensees will need to establish an account with Pay.Gov (*https://www.pay.gov*). To request an account, the licensee shall send an email to *det@nrc.gov.* The email must include the licensee's company name, address, point of contact (POC), POC email address, and phone number. The NRC will forward the request to Pay.Gov; who will contact the licensee with a password and user lD. Once the licensee has established an account and submitted payment to Pay.Gov, they shall obtain a receipt. The licensee shall submit the receipt from Pay.Gov to the NRC along with fingerprint cards. For additional guidance on making electronic payments, contact the Facilities Security Branch, Division of Facilities and Security, at 301–415–7513. Combined payment for multiple applications is acceptable. The application fee (currently $26) is the sum of the user fee charged by the FBI for each fingerprint card or other fingerprint record submitted by the NRC on behalf of a licensee, and an NRC processing fee, which covers administrative costs associated with NRC handling of licensee fingerprint submissions. The Commission will directly notify licensees who are subject to this regulation of any fee changes.

4. The Commission will forward to the submitting licensee all data received from the FBI as a result of the licensee's application(s) for CHRCs, including the FBI fingerprint record.

F. Right To Correct and Complete Information

1. Prior to any final adverse determination, the licensee shall make available to the individual the contents of any criminal history records obtained from the FBI for the purpose of assuring correct and complete information. Written confirmation by the individual of receipt of this notification must be maintained by the licensee for a period of one (1) year from the date of notification.

2. If, after reviewing the record, an individual believes that it is incorrect or incomplete in any respect and wishes to change, correct, or update the alleged deficiency, or to explain any matter in the record, the individual may initiate challenge procedures. These procedures include either direct application by the individual challenging the record to the agency (i.e., law enforcement agency) that contributed the questioned information, or direct challenge as to the accuracy or completeness of any entry on the criminal history record to the Assistant Director, Federal Bureau of Investigation Identification Division, Washington, DC 20537–9700 (as set forth in 28 CFR 16.30 through 16.34). In the latter case, the FBI forwards the challenge to the agency that submitted the data and requests that agency to verify or correct the challenged entry. Upon receipt of an official communication directly from the agency that contributed the original information, the FBI Identification Division makes any changes necessary in accordance with the information supplied by that agency. The licensee must provide at least 10 days for an individual to initiate an action challenging the results of a FBI CHRC after the record is made available for his/her review. The licensee may make a final access determination based on the criminal history record only upon receipt of the FBI's ultimate confirmation or correction of the record. Upon a final adverse determination on access to an ISFSI, the licensee shall provide the individual its documented basis for denial. Access to an ISFSI shall not be granted to an individual during the review process.

G. Protection of Information

1. The licensee shall develop, implement, and maintain a system for personnel information management with appropriate procedures for the protection of personal, confidential information. This system shall be designed to prohibit unauthorized access to sensitive information and to prohibit modification of the information without authorization.

2. Each licensee who obtains a criminal history record on an individual pursuant to this Order shall establish and maintain a system of files and procedures, for protecting the record and the personal information from unauthorized disclosure.

3. The licensee may not disclose the record or personal information collected and maintained to persons other than the subject individual, his/her representative, or to those who have a need to access the information in performing assigned duties in the process of determining suitability for unescorted access to the protected area of an ISFSI. No individual authorized to have access to the information may re-disseminate the information to any other individual who does not have the appropriate need to know.

4. The personal information obtained on an individual from a CHRC may be transferred to another licensee if the gaining licensee receives the individual's written request to re-disseminate the information contained in his/her file, and the gaining licensee verifies information such as the individual's name, date of birth, social security number, sex, and other applicable physical characteristics for identification purposes.

5. The licensee shall make criminal history records, obtained under this section, available for examination by an authorized representative of the NRC to determine compliance with the regulations and laws.

[FR Doc. 2014–00108 Filed 1–7–14; 8:45 am]

BILLING CODE 7590–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–71222; File No. SR–NYSEMKT–2013–86]

Self-Regulatory Organizations; NYSE MKT LLC; Notice of Filing of Amendment No. 2 and Order Granting Accelerated Approval of Proposed Rule Change, as Modified by Amendment Nos. 1 and 2 Thereto, To Adopt Commentary .03 to Rule 980NY To Limit the Volume of Complex Orders by a Single ATP Holder During the Trading Day

January 2, 2014.

I. Introduction

On October 28, 2013, NYSE MKT LLC (the ''Exchange'' or ''NYSE MKT'') filed with the Securities and Exchange Commission (''Commission''), pursuant

to Section 19(b)(1)[1] of the Securities Exchange Act of 1934 (''Act''),[2] and Rule 19b–4 thereunder,[3] a proposed rule change to adopt Commentary .03 to NYSE MKT Rule 980NY to limit the volume of complex orders that may be entered by a single ATP Holder during the trading day. On November 5, 2013, the Exchange submitted Amendment No. 1 to the proposed rule change. The proposed rule change, as modified by Amendment No. 1 thereto, was published for comment in the **Federal Register** on November 13, 2013.[4] The Commission received no comments on the proposed rule change. On December 23, 2013, the Exchange granted an extension of time for the Commission to act on the filing until January 3, 2014.[5] On December 24, 2013, the Exchange submitted Amendment No. 2 to the proposed rule change.[6] The Commission is publishing this notice to solicit comments on Amendment No. 2 from interested persons, and is approving the proposed rule change, as modified by Amendment Nos. 1 and 2, on an accelerated basis.

II. Description of the Proposed Rule Change

The Exchange currently ranks and tracks Electronic Complex Orders in the Consolidated Book in a ''complex order table.'' Although the Exchange stated that the complex order table has sufficient capacity to accept all Complex Orders submitted by all ATP Holders under normal operating conditions, the Exchange also noted that that capacity is not unlimited.[7] Given that this capacity is not unlimited, the Exchange proposes to adopt Commentary .03 to Rule 980NY[8] to provide that if an ATP Holder submits orders that comprise more than ''n%'' of the capacity of the complex order table (the ''Cap''), the Exchange will reject that ATP Holder's Electronic Complex Orders for the remainder of the trading day. Proposed Commentary .03 to Rule 980NY also provides a ''warning threshold'' of ''n%–x'' of the complex order table. If an ATP Holder breaches such warning threshold, it would result in the Exchange rejecting the ATP Holder's Electronic Complex Orders until such time that the ATP Holder has notified the Exchange to re-enable the submission of Electronic Complex Orders. The Exchange will not reject any Electronic Complex Orders until after an ATP Holder has breached either the warning threshold (*i.e.,* ''n%–x'') or the Cap.[9] The specified percentage (*i.e.,* ''n%'') will be no less than 60%, and ''n%–x'' will be no less than 40%.

The Exchange will announce the implementation date of the proposed rule change by Trader Update to be published no later than 60 days following approval by the Commission. The implementation date will be no later than 60 days following the issuance of the Trader Update.

III. Discussion and Commission Findings

After careful review, the Commission finds that the proposed rule change is consistent with the requirements of the Act and rules and regulations thereunder applicable to a national securities exchange.[10] In particular, the Commission finds that the proposed rule is consistent with Section 6(b)(5) of the Act,[11] which requires, among other things, that the rules of an exchange 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, in general, to protect investors and the public interest. The Commission believes that providing the Cap could provide the Exchange with a system protection tool to address the potential risk that a single ATP Holder could—either intentionally or inadvertently—utilize the entire complex order table, effectively shutting out all other ATP Holders' Electronic Complex Orders from the Exchange for the remainder of the trading day. By disabling the submission of Electronic Complex Orders of a single ATP Holder that has exceeded the Cap, the Cap should allow the Exchange to accommodate Electronic Complex Orders from all other ATP Holders, thereby helping to ensure efficient functionality of the complex order table and the protection of investors and the public interest. In approving this proposed rule change, the Commission notes that the Exchange represented that under normal operating conditions, the combined Electronic Complex Orders of all ATP Holders do not exceed 40% of the complex order table.[12] Therefore, the Exchange believes that setting the Cap for a single ATP Holder at 60% would allow 40% of the complex order table—which is typically sufficient to accommodate all ATP Holder's Electronic Complex Orders—to remain accessible to the balance of ATP Holders and would not unfairly deny these ATP Holders access to the market.[13]

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether Amendment No. 2 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–NYSEMKT–2013–86 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEMKT–2013–86. 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

[1] 15 U.S.C. 78s(b)(1).

[2] 15 U.S.C. 78a.

[3] 17 CFR 240.19b–4.

[4] *See* Securities Exchange Act Release No. 70816 (November 6, 2013), 78 FR 68111 (''Notice'').

[5] In addition, on December 24, 2013, the Commission extended the time period for Commission action to January 3, 2014. *See* Securities Exchange Act Release No. 71183 (December 24, 2013).

[6] In Amendment No. 2, the Exchange amended the proposed rule change by removing the language in the proposal that gives the Exchange discretion to adjust the specified percentage (*i.e.,* ''n%'') to an amount less than 60% and ''n%–x'' to an amount less than 40%. Amendment No. 2 has been placed in the public comment file for NYSEMKT–2013–86 at *http://www.sec.gov/comments/sr-nysemkt-2013-86/nysemkt201386.shtml* (*see* letter from Janet McGinness, EVP & Corporate Secretary, General Counsel, NYSE MKT, to Elizabeth M. Murphy, Secretary, Commission, dated December 26, 2013).

[7] According to the Exchange, the complex order table currently has the capacity to hold Electronic Complex Orders containing up to 16 million legs throughout the trading day. *See* Notice, *supra* note 4 at 68111, n. 8.

[8] Rule 980NY governs trading of Complex Orders on the NYSE MKT System (''Electronic Complex Orders'').

[9] For example, if an ATP Holder submits an Electronic Complex Order that, once accepted, breaches the Cap, the Exchange will accept that order in its entirety and then will reject all subsequent Electronic Complex Orders from that ATP Holder for the remainder of the trading day.

[10] In approving the proposed rule changes, the Commission has considered their impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[11] 15 U.S.C. 78f(b)(5).

[12] *See* Notice, *supra* note 4 at 68112. The Commission also notes that the Exchange represented that a single ATP Holder would only exceed the Cap (or receive a warning of a near breach) in the event of a bona fide problem (*e.g.,* a system error or malfeasance). *See id.*

[13] *See id.*

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 publicly available. All submissions should refer to File Number SR–NYSEMKT–2013–86 and should be submitted on or before January 29, 2014.

V. Accelerated Approval of Proposed Rule Change, as Modified by Amendment Nos. 1 and 2

As proposed, the proposed rule change provided that, unless determined otherwise by the Exchange and announced to ATP Holders via Trader Update, the specified percentage (*i.e.,* ''n%'') will be no less than 60%, and ''n%–x'' will be no less than 40%. Amendment No. 2 amended the proposed rule change by removing the language in the proposal that gives the Exchange discretion to adjust the specified percentage (*i.e.,* ''n%'') to an amount less than 60% and ''n%–x'' to an amount less than 40%. By removing this discretion, Amendment No. 2 reduces potential uncertainty about the application of the proposed rule change. Accordingly, the Commission finds good cause, pursuant to Section 19(b)(2) of the Act,[14] for approving the proposed rule change, as modified by Amendment Nos. 1 and 2, prior to the 30th day after the date of publication of notice in the **Federal Register**.

VI. Conclusion

It is therefore ordered, pursuant to Section 19(b)(2) of the Act [15] that the proposed rule change (SR–NYSEMKT–2013–86), as modified by Amendment Nos. 1 and 2, be, and hereby is, approved on an accelerated basis.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[16]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–00066 Filed 1–7–14; 8:45 am]

BILLING CODE 8011–01–P

[14] 15 U.S.C. 78s(b)(2).

[15] 15 U.S.C. 78f(b)(2).

[16] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–71227; File No. SR–CBOE–2013–110]

Self-Regulatory Organizations; Chicago Board Options Exchange, Incorporated; Order Approving a Proposed Rule Change To Eliminate the e-DPM Program January 2, 2014.

I. Introduction

On November 1, 2013, Chicago Board Options Exchange, Incorporated (the ''Exchange'' or ''CBOE'') filed with the Securities and Exchange Commission (''Commission'') pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'') [1] and Rule 19b–4 thereunder,[2] a proposed rule change to eliminate the Electronic DPM (''e-DPM'') Program (the ''e-DPM Program'' or ''Program''). The proposed rule change was published for comment in the **Federal Register** on November 20, 2013.[3] The Commission received no comments on the proposal. This order approves the proposed rule change.

II. Description of the Proposal

The Exchange proposes to eliminate the e-DPM Program by deleting Exchange rules that exclusively govern the Program and by removing all references to either the Program or e-DPMs throughout the remainder of its rulebook. Originally adopted in 2004, the e-DPM Program allows Trading Permit Holders (''TPHs'') to remotely function as a Designated Primary Market-Maker (''DPM'').[4] An e-DPM acts as a specialist on CBOE by entering bids and offers electronically from locations other than the floor-based trading crowds where applicable option classes are traded, and are not required to have traders physically present in the trading crowd.[5]

The Exchange proposes to eliminate the Program because it believes the Program is no longer competitively necessary given the growing prevalence of Preferred Market-Maker [6] (''PMM'') routing, which the Exchange believes has rendered the initially unique tenets of the Program less relevant and attractive to broker-dealers that might otherwise consider becoming or remaining an e-DPM.[7] In particular, the Exchange noted in its filing that while e-DPMs have similar or greater quoting obligations than PMMs, CBOE's rules provide a smaller participation entitlement to e-DPMs as compared to the participation entitlement that CBOE provides to PMMs.[8] The Exchange further represented that all e-DPMs that receive preferred orders on CBOE are also registered as PMMs.[9] The Exchange explained that the only circumstance in which it is a benefit to act as an e-DPM from the perspective of increasing a TPH's participation entitlement is where an order is not preferred to any party or the recipient of the preferred order is not at the NBBO when the order is received.[10] To place this attribute in context, the Exchange noted that 85% of orders that come into the Exchange are preferred orders.[11]

The Exchange stated that it does not believe that the elimination of the e-DPM Program will affect CBOE's market quality because the Exchange does not expect any Market-Makers to cease doing business on the Exchange due to

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 70875 (November 14, 2013), 78 FR 69723 (''Notice'').

[4] *See id.* at 69723. CBOE Rule 8.80(a) defines as a DPM as a ''TPH organization that is approved by the Exchange to function in allocated securities as a Market-Maker'' and is subject to certain obligations as provided in CBOE's rules. A DPM generally will operate on CBOE's trading floor, but can function remotely away from CBOE's trading floor in certain classes, subject to approval by the Exchange. *See* CBOE Rule 8.80(a).

[5] CBOE Rule 8.92, which the Exchange proposes to delete, defined an e-DPM as ''a TPH organization that is approved by the Exchange to remotely function in allocated option classes as a DPM and to fulfill certain obligations required of DPMs except for Floor Broker and Order Book Official obligations.''

[6] Pursuant to CBOE Rule 8.13, the PMM program permits the Exchange to ''allow on a class-by-class basis, for the receipt of marketable orders, through the Exchange's Order Routing System when the Exchange's disseminated quote is the NBBO, that carry a designation from the Trading Permit Holder transmitting the order that specifies a Market-Maker in that class as the 'Preferred Market-Maker' for that order. A qualifying recipient of a Preferred Market-Maker order shall be afforded a participation entitlement'' as set forth in CBOE Rule 8.13.

[7] *See* Notice, *supra* note 3, at 69723.

[8] *See id.* The Exchange stated that on most transactions to which the e-DPM entitlement applies, if no party is labeled ''preferred'' for that order, or the party labeled ''preferred'' is not at the NBBO, e-DPMs are only guaranteed a maximum of 15% participation entitlement per order, whereas PMMs have a maximum 40% participation entitlement on orders that are preferred to them. *See* Notice, *supra* note 3, at 69723–69724.

[9] *See id.* at 69723.

[10] *See id.* at 69724.

[11] *See id.*

the elimination of the Program; instead, the Exchange anticipates that all e-DPMs will stay on as Market-Makers and, on an order-by-order basis, as PMMs.[12] The Exchange believes that the greater participation entitlement under the PMM program when an order is preferred provides a stronger incentive for TPHs to quote at the NBBO than the lower participation entitlement for e-DPMs, which, according to the Exchange, helps to encourage narrower spreads.[13]

In support of its proposal to discontinue the e-DPM program, the Exchange further represented that it believes that the Program adds an unnecessary layer of complexity to CBOE rules, system processes, matching algorithms, and trading procedures.[14] The Exchange does not believe that the e-DPM Program provides CBOE with any competitive advantage, and believes that the elimination of the Program will provide the Exchange with more flexibility to consider other methods of encouraging DPM performance.[15]

In its filing, the Exchange represented that, if its proposal is approved by the Commission, CBOE would announce the elimination of the Program via a Regulatory Circular, which will include an end date for the Program that will be at least two weeks in advance in order for current e-DPMs to determine their course of action following elimination of the Program.[16]

III. Discussion and Commission Findings

After careful review of the proposal, the Commission finds 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.[17] In particular, the Commission finds that the proposed rule change is consistent with Section 6(b)(1) of the Act,[18] which requires, among other things, that the Exchange be so organized and have the capacity to carry out the purposes of the Act. The Commission also finds that the proposed rule change is consistent with Section 6(b)(5) of the Act,[19] which requires, among other things, that the rules of a national securities exchange be designed to prevent fraudulent and manipulative acts and practices, 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.

As noted above, CBOE represents that all e-DPMs are also registered as PMMs. Accordingly, CBOE does not believe that elimination of the Program will harm CBOE's market quality as it anticipates current e-DPMs will continue to serve as market-makers on the Exchange and as PMMs on orders that are preferred to them.

Further, because such a high percentage of CBOE's order-flow is preferenced (85% as indicated by CBOE), and because PMM status provides a comparably larger entitlement for preferred orders compared to e-DPM status, CBOE believes that the e-DPM program does not provide an incentive great enough to warrant the complexity the e-DPM program brings to the Exchange's rules, systems, and processes. CBOE also noted that other options exchanges do not have programs similar to the e-DPM program.[20]

Based on CBOE's representations, discussed above, the Commission believes that elimination of the e-DPM Program should not hinder the Exchange's capacity to carry out the purposes of the Act nor should it impede CBOE's ability to remove impediments to and perfect the mechanism of a free and open market and a national market system.

V. Conclusion

It is therefore ordered, pursuant to Section 19(b)(2) of the Act,[21] that the proposed rule change (SR–CBOE–2013–110) be, and hereby is, approved.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[22]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–00071 Filed 1–7–14; 8:45 am]

BILLING CODE 8011–01–P

[12] *See id.*

[13] *See id.*

[14] *See id.*

[15] *See id.*

[16] *See id.*

[17] In approving the proposal, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[18] 15 U.S.C. 78f(b)(1).

[19] 15 U.S.C. 78f(b)(5).

[20] *See* Notice, *supra* note 3, at 69724.

[21] 15 U.S.C. 78s(b)(2).

[22] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–71228; File No. SR–Phlx–2013–128]

Self-Regulatory Organizations; The NASDAQ OMX PHLX LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Further Describe the Application of Fees Assessed for Connectivity to the Carteret Test Environment under Chapter VIII of the Exchange's Pricing Schedule

January 2, 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 December 23, 2013, NASDAQ OMX PHLX LLC (''Phlx'' or the ''Exchange'') filed with the Securities and Exchange Commission (''Commission'') a proposed rule change as described in Items I and II below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of the Substance of the Proposed Rule Change

The Exchange proposes a rule change to further describe the application of fees assessed pursuant to subparagraph (d) of ''Testing Facilities'' under Chapter VIII of the Exchange's Pricing Schedule. The Exchange is also eliminating outdated text relating to the applicability of the fees assessed for use and connectivity to the Testing Facilities.

The text of the proposed rule change is below. Proposed new language is italicized. Proposed deletions are in brackets.

* * * * *

NASDAQ OMX PHLX LLC[1] PRICING SCHEDULE

ALL BILLING DISPUTES MUST BE SUBMITTED TO THE EXCHANGE IN WRITING AND MUST BE ACCOMPANIED BY SUPPORTING DOCUMENTATION. ALL DISPUTES MUST BE SUBMITTED NO LATER THAN SIXTY (60) DAYS AFTER RECEIPT OF A BILLING INVOICE, EXCEPT FOR DISPUTES CONCERNING NASDAQ OMX PSX FEES, PROPRIETARY DATA FEED FEES AND CO-LOCATION SERVICES FEES. AS OF JANUARY 3, 2011, THE EXCHANGE

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

WILL CALCULATE FEES ON A TRADE DATE BASIS.

[1] PHLX® is a registered trademark of The NASDAQ OMX Group, Inc.

* * * * *

VIII. NASDAQ OMX PSX FEES

* * * * *

Testing Facilities[†]

The Exchange operates two test environments. One is located in Ashburn, Virginia and the other in Carteret, New Jersey. Unless otherwise noted, reference to the ''Testing Facility'' applies to both environments.

(a)–(c) No change.

(d) Subscribers to the Testing Facility located in Carteret, New Jersey shall pay a fee of $1,000 per hand-off, per month for connection to the Testing Facility. The hand-off fee includes either a 1Gb or 10Gb switch port and a cross connect to the Testing Facility. Subscribers shall also pay a one-time installation fee of $1,000 per hand-off, which is waived for all installations ordered prior to March 31, 2014.

The connectivity provided under this rule also provides connectivity to the other test environments of NASDAQ OMX BX, Inc. and The NASDAQ Stock Market LLC.

[† Testing Facility fees will be waived for the period ending on the sixth full calendar month following the launch of NASDAQ OMX PSX.]

* * * * *

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 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 is proposing to amend the Phlx Pricing Schedule to more fully describe the application of the newly-adopted fee [3] assessed for direct connectivity to the Testing Facility [4] test environment located in Carteret, New Jersey (''Carteret''). The Testing Facility provides subscribers with a virtual Exchange System test environment that closely approximates the production environment and on which they may test their automated systems that integrate with the Exchange. The Exchange recently developed a test environment located in Carteret that provides NASDAQ OMX PSX (''PSX'') [5] equity trade testing functionality. The new test environment was developed together with equity test environments of the Phlx's sister exchanges, NASDAQ OMX BX, Inc. and The NASDAQ Stock Market LLC, also located at Carteret, New Jersey (collectively with PSX, the ''Equity Markets'').

The Exchange is proposing to add language to subparagraph (d) of ''Testing Facilities'' under Chapter VIII of the Exchange's Pricing Schedule that was erroneously omitted when the fee was originally adopted.[6] The new rule text explains that a firm that is a member of more than one of the Equity Markets may access the test environments of each of the Equity Markets of which it is a member through a single connectivity subscription under the rule. The Exchange notes that each of the Equity Markets has identical installation and hand-off fees for Carteret connectivity and these fees relate to the physical connection to the hardware infrastructure that houses all three test environments of the Equity Markets. Members of the Equity Markets must separately pay port fees to connect to the individual test environments of the Equity Markets of which it is a member within the hardware infrastructure housing them.[7] Therefore, a firm that is a member of multiple Equity Markets is not charged the Carteret connectivity fees for a hand-off under each of the identical rules of such markets, but rather is assessed a single market's Carteret connectivity fees. Consequently, a member organization of PSX using the Carteret test environment may be assessed the connectivity fee under another Equity Markets' rules of which it is a member, yet pay the PSX port fee to connect to the PSX test environment. Similarly, a member organization may subscribe to Carteret connectivity under the Phlx Pricing Schedule and not have an obligation to pay the same fee under the rules of the other Equity Markets of which it is a member, but have an obligation to pay those markets' port fees. The Exchange notes that, in adopting the identical fee for Carteret connectivity, NASDAQ OMX BX, Inc. included rule text consistent with the rule text proposed herein.[8] Accordingly, the Exchange is adding rule text to Carteret connectivity fee rule to reflect that the connectivity provided by the rule also provides access to the test environments of NASDAQ OMX BX, Inc. and The NASDAQ Stock Market LLC.

The Exchange is also eliminating text from the Testing Facilities rule that relates to a general waiver of fees under the rule, which was effective with the launch of PSX and ended six months thereafter. PSX launched in October 2010,[9] and consequently the fee waiver period has expired. Accordingly, the Exchange is removing the text relating to this fee waiver period.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act [10] in general, and with Section 6(b)(5) of the Act,[11] in particular. The Exchange believes the proposal furthers the objectives of Section 6(b)(5) of the Act [12] in that it is designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general to protect investors and the public interest and is not designed to permit unfair discrimination between customer, issuers, brokers and dealers. The Exchange is proposing to add clarifying language to the rule, which was erroneously omitted when the rule was adopted and further describes the application of the rule. Moreover, the proposed new rule text is consistent with the identical rule of NASDAQ OMX BX, Inc. and how fees are assessed under that rule. Last, the Exchange is proposing to eliminate outdated rule text from the rule, which serves no purpose. Accordingly, the Exchange believes that it is consistent with the protection of investors and the public

[3] *See* Securities Exchange Act Release No. 71036 (December 11, 2013), 78 FR 76350 (December 17, 2013) (SR–Phlx–2013–116).

[4] *See http://www.nasdaqtrader.com/Trader.aspx?id=TestingFacility* for a description of the Testing Facility.

[5] PSX is the Phlx equity market.

[6] *Supra* note 3.

[7] Phlx Pricing Schedule, Chapter VIII Testing Facilities subparagraph (a), NASDAQ Rule 7030(d)(1)(B), and BX Rule 7030(d)(1).

[8] *See* Securities Exchange Act Release No. 71035 (December 11, 2013), 78 FR 76344 (December 17, 2013) (SR–BX–2013–058).

[9] *See http://www.nasdaqtrader.com/Tradernews.aspx?id=eta2010-56.*

[10] 15 U.S.C. 78f(b).

[11] 15 U.S.C. 78f(b)(5).

[12] *Id.*

interest to avoid potential market participant confusion that may be caused by the omission of the proposed rule text and the inclusion of outdated rule text.

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. The proposed rule change clarifies how fees will be assessed to a firm that is a member of more than one of the Equity Markets and makes clear that a member organization may gain access to the test environments of the other Equity Markets through a subscription under the rule. Members of multiple Equity Markets are assessed the same fee for Carteret connectivity and must pay the port fees of each of the Equity Markets to gain access to such markets' test environments. In addition, the proposed change eliminates rule text that relates to a fee waiver that has since expired. As a consequence, the Exchange does not believe that the proposed rule change is impactful to competition in any respect.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The Exchange has filed the proposed rule change pursuant to Section 19(b)(3)(A) of the Act [13] and Rule 19b–4(f)(6) [14] thereunder. Because the foregoing proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A) of the Act [15] and subparagraph (f)(6) of Rule 19b–4 thereunder.[16]

A proposed rule change filed under Rule 19b–4(f)(6) [17] normally does not become operative prior to 30 days after the date of the filing. However, pursuant to Rule 19b–4(f)(6)(iii),[18] 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. The Exchange notes that such waiver will allow the Exchange to immediately add language to its rule text that was incorrectly omitted from a previous rule change, thereby clarifying its rules and avoiding potential market participant confusion.[19] The Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest as the proposal is designed to avoid potential investor confusion regarding the Exchange's rules and provide clarification to the public. For these reasons, the Commission hereby waives the 30-day operative delay and designates the proposal operative upon filing.[20]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule change should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include File Number SR–Phlx–2013–128 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–Phlx–2013–128. 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 offices 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–Phlx–2013–128, and should be submitted on or before January 29, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[21]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–00072 Filed 1–7–14; 8:45 am]

BILLING CODE 8011–01–P

[13] 15 U.S.C. 78s(b)(3)(A).

[14] 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 text of the proposed rule change, at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

[15] 15 U.S.C. 78s(b)(3)(A).

[16] 17 CFR 240.19b–4(f)(6).

[17] *Id.*

[18] 17 CFR 240.19b–4(f)(6)(iii).

[19] *See* SR–Phlx–2013–128, Item 7.

[20] For purposes only of waiving the 30-day operative delay, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[21] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–71231; File No. SR–FINRA–2013–055]

Self-Regulatory Organizations; Financial Industry Regulatory Authority, Inc.; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change Relating to Rule 2360 (Options) Position Limits

January 2, 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 December 23, 2013, Financial Industry Regulatory Authority, Inc. (''FINRA'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I and II below, which Items have been prepared by FINRA. FINRA has designated the proposed rule change as constituting a ''non-controversial'' rule change under paragraph (f)(6) of Rule 19b–4 under the Act,[3] which renders the proposal effective upon receipt of this filing by 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

FINRA is proposing to amend FINRA Rule 2360 (Options) to: (1) Specify that position limits for standardized equity options shall be the highest position limit established by an options exchange on which the option trades, which has the effect of eliminating position limits on standardized options on Standard and Poor's Depositary Receipts Trust (''SPY'') and increasing the position limit for standardized options on iShares MSCI Emerging Markets Index Fund (''EEM'') to 500,000 contracts; and (2) increase the position limit for conventional options on EEM to 500,000 contracts.

The text of the proposed rule change is available on FINRA's Web site at *http://www.finra.org,* at the principal office of FINRA 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, FINRA included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. FINRA has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

FINRA Rule 2360(b)(3)(A) imposes a position limit on the number of equity options contracts in each class on the same side of the market that can be held or written by a member, a person associated with a member, or a customer or a group of customers acting in concert. Position limits are intended to prevent the establishment of options positions that can be used to manipulate or disrupt the underlying market or might create incentives to manipulate or disrupt the underlying market so as to benefit the options position. In addition, position limits serve to reduce the potential for disruption of the options market itself, especially in illiquid options classes. FINRA understands that the Commission, when considering the appropriate level at which to set options position and exercise limits, seeks to prevent investors from disrupting the market in the security underlying the option.[4] This consideration has been balanced by the concern that the limits ''not be established at levels that are so low as to discourage participation in the options market by institutions and other investors with substantial hedging needs or to prevent specialists and market-makers from adequately meeting their obligations to maintain a fair and orderly market.'' [5]

Currently, Rule 2360(b)(3)(A) establishes position limits for equity options according to a five-tiered system in which options on more actively traded stocks with larger public floats are subject to higher position limits. Rule 2360 does not specifically govern how a particular equity option falls within one of the tiers. Rather, the position limit established by the rules of an options exchange for a particular equity option is the applicable position limit for purposes of Rule 2360.[6] Position limits for conventional equity options typically are the same as the limits for standardized equity options for which the underlying security qualifies or would be able to qualify.[7]

Standardized Options

As noted above, Rule 2360 provides that the five-tiered position limits established by the rules of an options exchange governs standardized equity options position limits. However, at times the options exchanges have increased position limits beyond the highest tier (currently 250,000 contracts) for certain exchange-traded funds (''ETF'') options. For example, the options exchanges raised the position limit for standardized options on 'SPY [sic] options to 900,000 contracts.[8] In response, FINRA filed a corresponding rule change.[9] Recently, the options exchanges amended position limits again to eliminate the position limit for standardized SPY options [10] and raise

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 17 CFR 240.19b–4(f)(6).

[4] *See* Securities Exchange Act Release No. 40969 (January 22, 1999), 64 FR 4911, 4912–4913 (February 1, 1999) (Order Approving File No. SR–CBOE–98–23) (citing H.R. No. IFC–3, 96th Cong., 1st Sess. at 189–91 (Comm. Print 1978)).

[5] *Id.* at 4913.

[6] *See* CBOE Rule 4.11; ISE Rule 412; NASDAQ OMX PHLX Rule 1001; NYSE Amex Rule 904; NYSE Arca Rule 6.8; BOX Rule 3120 and IM–3120–2; Nasdaq Chapter III, Section 7; BX Chapter III, Section 7; and BATS Rule 18.7.

[7] *See* Rule 2360(b)(3)(A)(viii). Standardized equity option contracts on the same side of the market overlying the same security are not aggregated with conventional equity option contracts or FLEX Equity Option contracts.

[8] *See* the options exchanges' filings to increase the position limits on SPY options to 900,000 contracts in Securities Exchange Act Release No. 64695 (June 17, 2011), 76 FR 36942 (June 23, 2011) (Order Approving File No. SR–Phlx–2011–58); Securities Exchange Act Release No. 64760 (June 28, 2011), 76 FR 39143 (July 5, 2011) (Notice of Filing and Immediate Effectiveness of File No. SR–ISE–2011–34); Securities Exchange Act Release No. 64928 (July 20, 2011), 76 FR 44633 (July 26, 2011) (Notice of Filing and Immediate Effectiveness of File No. SR–CBOE–2011–065); Securities Exchange Act Release No. 64966 (July 26, 2011), 76 FR 45899 (August 1, 2011) (Notice of Filing and Immediate Effectiveness of File No. SR–NYSEAmex–2011–50); and Securities Exchange Act Release No. 64945 (July 21, 2011), 76 FR 44969 (July 27, 2011) (Notice of Filing and Immediate Effectiveness of File No. SR–NYSEArca–2011–47).

[9] *See* Securities Exchange Act Release No. 65086 (August 10, 2011), 76 FR 50796 (August 16, 2011) (Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Increase the Position Limit for Options on the Standard and Poor's Depositary Receipts Trust; File No. SR–FINRA–2011–036).

[10] *See* the options exchanges' filings to eliminate position limits on SPY options on a pilot basis in Securities Exchange Act Release No. 67672 (August 15, 2012), 77 FR 50750 (August 22, 2012) (Order Approving File No. SR–NYSEAmex–2012–29); Securities Exchange Act Release No. 67937 (September 27, 2012), 77 FR 60489 (October 3, 2012) (Notice of Filing and Immediate Effectiveness of File No. SR–CBOE–2012–091); Securities Exchange Act Release No. 67999 (October 5, 2012), 77 FR 62295 (October 12, 2012) (Notice of Filing and Immediate Effectiveness of File No. SR–Phlx–2012–122); Securities Exchange Act Release No. 68000 (October 5, 2012), 77 FR 62300 (October 12, 2012) (Notice of Filing and Immediate Effectiveness of File No. SR–ISE–2012–81); Securities Exchange Act Release No. 68001 (October 5, 2012), 77 FR 62303 (October 12, 2012) (Notice of Filing and Immediate Effectiveness of File No. SR–NYSEArca–

the position limit for standardized EEM options.[11] Instead of continuing to file separate proposed rule changes to harmonize the FINRA provision regarding position limits for such standardized equity options with those of the options exchanges, FINRA proposes to amend Rule 2360(b)(3)(A) (and re-number it as Rule 2360(b)(3)(A)(i)) to eliminate reference to the specific five tiers and in their place specify that a member shall not hold or control or be obligated in respect of an aggregate standardized equity options position in excess of the highest position limit established by an exchange on which the option trades.[12] As a result, under the proposed rule change, the position limits for standardized options on EEM would be 500,000 contracts and there would be no position limit for standardized options on SPY consistent with the options exchange provisions.

The proposed rule change would allow members to immediately take advantage of any increased standardized equity option position limit that may be set by an options exchange as approved by the SEC without waiting for FINRA to file a corresponding rule change.[13] The proposed rule change is consistent with FINRA's provision regarding position limits on index options, which incorporates the position limits as set by the options exchange on which the index option trades.[14]

Conventional Options

As noted above, currently position limits for conventional options are the same as the limits for standardized options for which the underlying security qualifies or would be able to qualify.[15] FINRA proposes to maintain this structure for purposes of securities that have position limits within the five-tiers (*i.e.,* up to the 250,000 contract position limit). Accordingly, FINRA proposes to amend Rule 2360(b)(3)(A)(viii) (and re-number it as Rule 2360(b)(3)(A)(iii)) to provide that conventional equity options shall be subject to a basic position limit of 25,000 contracts or a higher tier for conventional option contracts on securities that underlie exchange-traded options qualifying for such higher tier as determined by the rules of the options exchanges. In addition, for options on securities that have higher position limits—currently, only the ETFs listed in Supplementary Material .03—FINRA proposes to incorporate such position limits for conventional options on ETFs into the body of the text. At this time, FINRA also proposes to conform to the options exchanges' recent amendments that increased the position limit to 500,000 contracts for standardized options on EEM by increasing the position limit applicable to conventional options on EEM to 500,000 contracts.[16]

In support of the increased position limit on conventional EEM options, below are the trading statistics comparing EEM to IWM and SPY. As shown in the following table, the average daily volume in 2012 for EEM was 49.4 million shares compared to 45.7 million shares for IWM and 143.3 million shares for SPY. The total shares outstanding for EEM were 911.7 million compared to 243.7 million shares for IWM and 837.5 million shares for SPY. Further, the fund market cap for EEM was $34.1 billion compared to $24.6 billion for IWM and $137.2 billion for SPY.

ETF	2012 ADV (mil. shares)	2012 ADV (option contracts)	Shares outstanding (mil.)	Fund market cap ($bil)
EEM	49.4	256,453	911.7	34.1
IWM	45.7	498,102	243.7	24.6
SPY	143.3	2,342,942	837.5	137.2

In further support of this proposal, as noted by CBOE, EEM tracks the performance of the MSCI Emerging Markets Index, which has approximately 800 component securities.[17] As noted on MSCI's Web site: ''[t]he MSCI Emerging Markets Index is a free float-adjusted market capitalization index that is designed to measure equity market performance of emerging markets. The MSCI Emerging Markets Index consists of the following 21 emerging market country indices: Brazil, Chile, China, Colombia, Czech Republic, Egypt, Greece, Hungary, India, Indonesia, Korea, Malaysia, Mexico, Peru, Philippines, Poland, Russia, South Africa, Taiwan, Thailand, and Turkey.'' [18] CBOE, in its filing, indicated that EEM still qualifies for the initial listing criteria set forth in CBOE Rule

2012–112); and Securities Exchange Act Release No. 67936 (September 27, 2012), 77 FR 60491 (October 3, 2012) (Notice of Filing of File No. SR–BOX–2012–013). NYSE MKT, CBOE and PHLX recently have extended their pilot programs. *See* Securities Exchange Act Release No. 70734 (October 22, 2013), 78 FR 64255 (October 28, 2013) (Notice of Filing and Immediate Effectiveness of File No. SR–NYSEMKT–2013–83); Securities Exchange Act Release No. 70878 (November 14, 2013), 78 FR 69737 (November 20, 2013) (Notice of Filing and Immediate Effectiveness of File No. SR–CBOE–2013–106); and Securities Exchange Act Release No. 70879 (November 14, 2013), 78 FR 69731 (November 20, 2013) (Notice of Filing and Immediate Effectiveness of File No. SR–Phlx–2013–108).

[11] *See* the options exchanges' filings to increase the position limits on EEM options to 500,000 contracts in Securities Exchange Act Release No. 68086 (October 23, 2012), 77 FR 65600 (October 29, 2012) (Order Approving File No. SR–CBOE–2012–066); Securities Exchange Act Release No. 68293 (November 27, 2012), 77 FR 71644 (December 3, 2012) (Notice of Filing and Immediate Effectiveness of File No. SR–Phlx–2012–132); Securities Exchange Act Release No. 68398 (December 11, 2012), 77 FR 74700 (December 17, 2012) (Notice of Filing and Immediate Effectiveness of File No. SR–ISE–2012–93); Securities Exchange Act Release No. 68359 (December 5, 2012), 77 FR 73716 (December 11, 2012) (Notice of Filing and Immediate Effectiveness of File No. SR–NYSEArca–2012–132); Securities Exchange Act Release No. 68358 (December 5, 2012), 77 FR 73708 (December 11, 2012) (Notice of Filing and Immediate Effectiveness of File No. SR–NYSEMKT–2012–71); and Securities Exchange Act Release No. 68478 (December 19, 2012), 77 FR 76132 (December 26, 2012) (Notice of Filing and Immediate Effectiveness of SR–BOX–2012–023).

[12] Rule 2360(b)(4) sets forth exercise limits through incorporating by reference options position limits under the rule. Accordingly, although the proposed rule change would not amend the text of Rule 2360(b)(4), the proposed rule change also would correspondingly raise exercise limits on the applicable standardized equity option.

[13] With respect to future potential increases for position limits by an options exchange, FINRA members would be able to take advantage of any increased position limit subject to the rules of any other options exchange of which such FINRA member may also be a member. For example, if CBOE increases the position limit on XYZ options to 300,000 contracts (from 250,000 contracts), then any CBOE and FINRA member (or a FINRA-only member) would be entitled to use the higher limit. However, if the FINRA member is also a member of the ISE and the ISE has not yet raised the position limit on XYZ options, such member would be bound by the lower ISE position limit.

[14] *See* Rule 2360(b)(3)(B).

[15] *See* note 7.

[16] *See* note 11.

[17] *See http://us.ishares.com/product_info/fund/overview/EEM.htm* and *http://www.msci.com/products/indices/licensing/msci_emerging_markets/*. Identification of the specific securities in the MSCI Emerging Markets Index and their individual concentrations in the MSCI Emerging Markets Index can be accessed at: *http://us.ishares.com/product_info/fund/holdings/EEM.htm.*

[18] *See http://www.msci.com/products/indices/tools/index.html#EM.*

5.3.06(v) and that more than 50% of the weight of the securities held by EEM are subject to a comprehensive surveillance agreement (''CSA'').[19] In addition, CBOE further notes that the component securities of the MSCI Emerging Markets Index on which EEM is based for which the primary market is in any one country that is not subject to a CSA do not represent 20% or more of the weight of the MSCI Emerging Markets Index.[20] Finally, the component securities of the MSCI Emerging Markets Index on which EEM is based for which the primary market is in any two countries that are not subject to CSAs do not represent 33% or more of the weight of the MSCI Emerging Markets Index.[21]

FINRA believes that the liquidity in the underlying ETF and the liquidity in EEM options support its request to increase the position limits for conventional EEM options as similar to the standardized EEM options. Through November 29, 2013, the year-to-date average daily trading volume in the ETF for EEM across all exchanges was 62 million shares. The year-to-date average daily trading for EEM options across all exchanges was 327,347 contracts.

FINRA believes that increasing position limits for EEM conventional options will lead to a more liquid and competitive market environment for EEM options that will benefit customers interested in this product.

Surveillance and Reporting

Further, FINRA believes that the modified position limits provisions are appropriate in light of the existing surveillance procedures and reporting requirements at FINRA,[22] the options exchanges, and at the several clearing firms, which are capable of properly identifying unusual or illegal trading activity. These procedures use daily monitoring of market movements by automated surveillance techniques to identify unusual activity in both options and underlying stocks.[23]

In addition, large stock holdings must be disclosed to the Commission by way of Schedules 13D or 13G.[24] Options positions are part of any reportable positions and cannot legally be hidden. Moreover, the previously noted Rule 2360(b)(5) requirement that members must file reports with FINRA for any customer that held aggregate large long or short positions of any single class for the previous day will continue to serve as an important part of FINRA's surveillance efforts.

Finally, FINRA believes that the current financial requirements imposed by FINRA and by the Commission adequately address financial responsibility concerns that a member or its customer will maintain an inordinately large unhedged position in any option with a higher position limit. Current margin and risk-based haircut methodologies serve to limit the size of positions maintained by any one account by increasing the margin or capital that a member must maintain for a large position. Under Rule 4210(f)(8)(A), FINRA also may impose a higher margin requirement upon a member when FINRA determines a higher requirement is warranted. In addition, the Commission's net capital rule[25] imposes a capital charge on members to the extent of any margin deficiency resulting from the higher margin requirement.

FINRA has filed the proposed rule change for immediate effectiveness and has requested that the SEC waive the requirement that the proposed rule change not become operative for 30 days after the date of the filing, so FINRA can implement the proposed rule change immediately.

2. Statutory Basis

FINRA believes that the proposed rule change is consistent with the provisions of Section 15A(b)(6) of the Act,[26] which requires, among other things, that FINRA rules must be designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, and, in general, to protect investors and the public interest. FINRA believes that the proposed rule change promotes consistent regulation by harmonizing position limits on standardized equity options with those of the other self-regulatory organizations. FINRA further believes that increasing the position limit on conventional EEM options promotes consistent regulation by harmonizing the position limit with its standardized counterpart. In addition, FINRA believes the proposed rule change will be beneficial to large market makers and institutions (which generally have the greatest ability to provide liquidity and depth in products that may be subject to higher position limits as has been the case with recently approved increased position limits[27]), as well as retail traders, investors and public customers, by providing them with a more effective trading and hedging vehicle.

B. Self-Regulatory Organization's Statement on Burden on Competition

FINRA does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act. As noted above, the proposed rule change would amend Rule 2360 to harmonize FINRA's position limits on standardized options with those of the options exchange (which are subject to approval by the SEC), and to harmonize position limits for conventional EEM options with the position limit for standardized EEM options.[28] Under the current rule, broker-dealers that are members of FINRA remain subject to the lower FINRA specified contract position limit and may not avail themselves of the higher position limit as set by an options exchange until FINRA can file a corresponding change. FINRA believes that the proposed rule change promotes consistent regulation by harmonizing standardized equity option position limits with those of the options exchanges and by harmonizing conventional EEM options position limits with their standardized counterpart. FINRA believes that setting consistent position limits for standardized options does not result in any burden on competition and would allow market participants to compete equally regardless of membership with an options exchange. Likewise, FINRA believes that harmonizing position limits for conventional EEM options does not result in any burden on competition and would allow market participants in the conventional EEM options market to compete effectively with participants using the standardized counterpart.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Because the foregoing proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on

[19] *See* note 11.

[20] *See* note 11.

[21] *See* note 11.

[22] *See* Rule 2360(b)(5) for the options reporting requirements.

[23] These procedures have been effective for the surveillance of options trading and will continue to be employed.

[24] 17 CFR 240.13d–1.

[25] 17 CFR 240.15c3–1.

[26] 15 U.S.C. 78*o*–3(b)(6).

[27] *See* notes 10 and 11.

[28] *See* notes 10 and 11.

which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A) of the Act [29] and Rule 19b–4(f)(6) thereunder.[30]

A proposed rule change filed under Rule 19b–4(f)(6) [31] normally does not become operative prior to 30 days after the date of the filing. However, pursuant to Rule 19b–4(f)(6)(iii),[32] the Commission may designate a shorter time if such action is consistent with the protection of investors and the public interest. FINRA has asked the Commission to waive the 30-day operative delay so that FINRA may immediately harmonize position limits with those of other self-regulatory organizations to ensure consistent regulation for the protection of investors and the public interest. The Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest. Therefore, the Commission hereby waives the 30-day operative delay and designates the proposal operative upon filing.[33]

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–FINRA–2013–055 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number *SR–FINRA–2013–055.* 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 FINRA. 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–FINRA–2013–055 and should be submitted on or before January 29, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[34]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–00075 Filed 1–7–14; 8:45 am]

BILLING CODE 8011–01–P

[29] 15 U.S.C. 78s(b)(3)(A).

[30] 17 CFR 240.19b–4(f)(6). In addition, Rule 19b–4(f)(6) requires a self-regulatory organization to give the Commission written notice of its intent to file the proposed rule change, along with a brief description and text of the proposed rule change, at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. FINRA has satisfied this requirement.

[31] 17 CFR 240.19b–4(f)(6).

[32] 17 CFR 240.19b–4(f)(6)(iii).

[33] For purposes only of waiving the 30-day operative delay, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[34] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–71230; File No. SR–ISE–2013–74]

Self-Regulatory Organizations; International Securities Exchange, LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend the Schedule of Fees

January 2, 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 December 20, 2013, the International Securities Exchange, LLC (the ''Exchange'' or the ''ISE'') 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 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 ISE proposes to amend its Schedule of Fees to extend its Managed Data Access Service Pilot for the sale of a number of real-time market data products. 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.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

On June 6, 2013 the ISE implemented a Managed Data Access Service Pilot that established a new pricing and distribution model for the sale of a number of real-time market data products.[3] The Exchange now proposes to extend that pilot for an additional 6 month period ending May 30, 2014 so that the Exchange can continue to provide this alternative delivery option for ISE data feeds.[4] Managed Data Access Service is a pricing and administrative option whereby the ISE assesses fees to Managed Data Access Distributors,[5] who redistribute market data to Managed Data Access Recipients.[6] Managed Data Access Distributors are required to monitor the delivery of the data retransmitted to their clients, and must agree to reformat, redisplay and/or alter the data feeds prior to retransmission without affecting the integrity of the data feeds and without rendering any of the feeds inaccurate, unfair, uninformative, fictitious, misleading, or discriminatory.

The current fees for the Managed Data Access Service, which are proposed to be extended for another 6 month pilot period, are as follows:

The Exchange charges a fee to each Managed Data Access Distributor of $2,500 per month for the Depth Feed, $1,500 for each of the Top Quote Feed and Spread Feed, and $1,000 per month for the Order Feed. The Exchange also charges a fee for each IP address at Managed Data Access Recipients that receive market data redistributed by a Managed Data Access Distributor, which is $750 per month for the Depth Feed, $500 per month for each of the Top Quote Feed and Spread Feed, and $350 per month for the Order Feed.[7] In addition, the Exchange charges a controlled device fee for each controlled device permitted to access market data redistributed by a Managed Data Access Distributor to a Market Data Access Recipient that is a Professional user,[8] which is $50 per month for the Depth Feed, $20 per month for the Top Quote Feed, $25 per month for the Spread Feed, and $10 per month for the Order Feed.[9] Finally, the Exchange charges a controlled device fee of $5 per month for each controlled device permitted to access information in the Depth Feed redistributed by a Managed Data Access Distributor to a Market Data Access Recipient that is a Non-Professional user.[10] For each of the above ISE data feeds, Market Data Access Distributors are subject to a minimum fee, which is $5,000 per month for the Depth Feed, $3,000 per month for each of the Top Quote Feed and Spread Feed, and $2,000 per month for the Order Feed.

The Exchange is not proposing to make any changes to the fees currently charged under the Managed Data Access Service program.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with the provisions of Section 6 of the Act,[11] in general, and Section 6(b)(4) of the Act,[12] 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. The Exchange already runs a Managed Data Access Service program, and is merely proposing to extend its pilot for an additional 6 month period. The Exchange initially established this program on a pilot basis in order gauge the level of interest in this new pricing and distribution model, and now wishes to extend this pilot so that it may continue to offer this product. The Exchange continues to believe that the fees for this program, which will be extended for an additional 6 month period, are fair and equitable. The Managed Data Access Service promotes broader distribution of controlled data, while offering a pricing option that should result in lower fees for subscribers. The Exchange is constrained in pricing the Managed Data Access Service as these services are entirely optional, and firms may choose whether or not to purchase proprietary ISE market data products or to utilize any specific pricing alternative. Moreover, the program is not unfairly discriminatory because it provides an opportunity for all distributors and subscribers, both Professional and Non-Professional, to access the ISE data feeds at a potentially lower cost.

B. Self-Regulatory Organization's Statement on Burden on Competition

In accordance with Section 6(b)(8) of the Act,[13] 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. To the contrary, the Exchange believes that the proposed rule change will promote competition as it extends a pilot that provides an attractive alternative pricing model for ISE market data. The vigor of competition for market data is significant and the Exchange believes that this proposal clearly evidences such competition. ISE proposes to continue to offer this optional Managed Access Data Service pricing model in order to keep pace with changes in the industry and evolving customer needs.

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

[3] *See* Securities Exchange Act Release No. 69806 (June 20, 2013), 78 FR 38424 (June 26, 2013) (ISE–2013–39). The Exchange also offers a similar Managed Data Access Service program for its Implied Volatility and Greeks Feed. *See* Securities Exchange Act Release No. 65678 (November 3, 2011), 76 FR 70178 (November 10, 2011) (ISE–2011–67). This filing does not apply to the Managed Data Access Service program for the Implied Volatility and Greeks Feed, which is not operated as a pilot.

[4] The current Managed Data Access Service pilot provides an alternative delivery option for the Real-time Depth of Market Raw Data Feed (''Depth Feed''), the Order Feed, the Top Quote Feed, and the Spread Feed.

[5] A Managed Data Access Distributor redistributes ISE data feeds and permits access to the information in those data feeds through a controlled device. A Managed Data Access Distributor can also redistribute a data feed solution to specific IP addresses, including an Application Programming Interface (''API'') or similar automated delivery solutions, with only limited entitlement controls (*e.g.,* usernames and/or passwords) to a recipient of the information.

[6] A Managed Data Access Recipient is a subscriber to the Managed Data Access Distributor who receives a reformatted data feed in a controlled device or at a specific IP address. Market Data Access Recipients may be Professional or Non-Professional users.

[7] This fee is charged per IP address, which covers both primary and back-up IP addresses at a Managed Data Access Recipient.

[8] A ''Professional user'' is an authorized end-user of the ISE data feeds that has not qualified as a Non-Professional user.

[9] A controlled device is any device that a distributor of an ISE data feed permits to access the information in that data feed.

[10] There is no controlled device fee for Non-Professional users of the Top Quote Feed, Spread Feed, or Order Feed. A ''Non-Professional user'' is an authorized end-user of the ISE data feeds who is a natural person and who is neither: (a) Registered or qualified with the Securities and Exchange Commission, the Commodities Futures Trading Commission, any state securities agency, any securities exchange or association, or any commodities or futures contract market or association; (b) engaged as an ''investment advisor'' as that term is defined Section 202(a)(11) of the Investment Advisers Act of 1940 (whether or not registered or qualified under that act); nor (c) employed by a bank or other organization exempt from registration under Federal and/or state securities laws to perform functions that would require him/her to be so registered or qualified if he/she were to perform such functions for an organization not so exempt.

[11] 15 U.S.C. 78f.

[12] 15 U.S.C. 78f(b)(4).

[13] 15 U.S.C. 78f(b)(8).

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 [14] and Rule 19b–4(f)(2) thereunder,[15] because it establishes a due, fee, or other charge imposed by ISE.

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–ISE–2013–74 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–ISE–2013–74. 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 ISE. 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–2013–74 and should be submitted on or before January 29, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[16]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–00074 Filed 1–7–14; 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)(2).

[16] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–71221; File No. SR–NYSEArca–2013–115]

Self-Regulatory Organizations; NYSE Arca, Inc.; Notice of Filing of Amendment No. 2 and Order Granting Accelerated Approval of Proposed Rule Change, as Modified by Amendment Nos. 1 and 2 Thereto, To Adopt Commentary .03 to Rule 6.91 To Limit the Volume of Complex Orders by a Single OTP Holder or OTP Firm During the Trading Day

January 2, 2014.

I. Introduction

On October 28, 2013, NYSE Arca, Inc. (the ''Exchange'' or ''NYSE Arca'') filed with the Securities and Exchange Commission (''Commission''), pursuant to Section 19(b)(1) [1] of the Securities Exchange Act of 1934 (''Act''),[2] and Rule 19b–4 thereunder,[3] a proposed rule change to adopt Commentary .03 to NYSE Arca Rule 6.91 to limit the volume of complex orders that may be entered by a single OTP Holder or OTP Firm (collectively, ''OTPs'') during the trading day. On November 5, 2013, the Exchange submitted Amendment No. 1 to the proposed rule change. The proposed rule change, as modified by Amendment No. 1 thereto, was published for comment in the **Federal Register** on November 13, 2013.[4] The Commission received no comments on the proposed rule change. On December 23, 2013, the Exchange granted an extension of time for the Commission to act on the filing until January 3, 2014.[5] On December 24, 2013, the Exchange submitted Amendment No. 2 to the proposed rule change.[6] The Commission is publishing this notice to solicit comments on Amendment No. 2 from interested persons, and is approving the proposed rule change, as modified by Amendment Nos. 1 and 2, on an accelerated basis.

II. Description of the Proposed Rule Change

The Exchange currently ranks and tracks Electronic Complex Orders in the Consolidated Book in a ''complex order table.'' Although the Exchange stated that the complex order table has sufficient capacity to accept all Complex Orders submitted by all OTPs under normal operating conditions, the Exchange also noted that that capacity is not unlimited.[7] Given that this capacity is not unlimited, the Exchange proposes to adopt Commentary .03 to Rule 6.91 [8] to provide that if an OTP submits orders that comprise more than ''n%'' of the capacity of the complex order table (the ''Cap''), the Exchange will reject that OTP's Electronic Complex Orders for the remainder of the trading day. Proposed Commentary .03 to Rule 6.91 also provides a ''warning threshold'' of ''n%—x'' of the complex order table. If an OTP breaches such warning threshold, it would result in the Exchange rejecting the OTP's

[1] 15 U.S.C. 78s(b)(1).

[2] 15 U.S.C. 78a.

[3] 17 CFR 240.19b–4.

[4] *See* Securities Exchange Act Release No. 70817 (November 6, 2013), 78 FR 68113 (''Notice'').

[5] In addition, on December 24, 2013, the Commission extended the time period for Commission action to January 3, 2014. *See* Securities Exchange Act Release No. 71184 (December 24, 2013).

[6] In Amendment No. 2, the Exchange amended the proposed rule change by removing the language in the proposal that gives the Exchange discretion to adjust the specified percentage (*i.e.,* ''n%'') to an amount less than 60% and ''n%-x'' to an amount less than 40%. Amendment No. 2 has been placed in the public comment file for NYSEArca–2013–115 at *http://www.sec.gov/comments/sr-nysearca-2013-115/nysearca2013115.shtml* (*see* letter from Janet McGinness, EVP & Corporate Secretary, General Counsel, NYSE Arca, to Elizabeth M. Murphy, Secretary, Commission, dated December 26, 2013).

[7] According to the Exchange, the complex order table currently has the capacity to hold Electronic Complex Orders containing up to 14 million legs throughout the trading day. *See* Notice, *supra* note 4 at 68114, n. 8.

[8] Rule 6.91 governs trading of Complex Orders on the NYSE Arca System (''Electronic Complex Orders'').

Electronic Complex Orders until such time that the OTP has notified the Exchange to re-enable the submission of Electronic Complex Orders. The Exchange will not reject any Electronic Complex Orders until after an OTP has breached either the warning threshold (*i.e.,* ''n%-x'') or the Cap.[9] The specified percentage (*i.e.,* ''n%'') will be no less than 60%, and ''n%-x'' will be no less than 40%.

The Exchange will announce the implementation date of the proposed rule change by Trader Update to be published no later than 60 days following approval by the Commission. The implementation date will be no later than 60 days following the issuance of the Trader Update.

III. Discussion and Commission Findings

After careful review, the Commission finds that the proposed rule change is consistent with the requirements of the Act and rules and regulations thereunder applicable to a national securities exchange.[10] In particular, the Commission finds that the proposed rule is consistent with Section 6(b)(5) of the Act,[11] which requires, among other things, that the rules of an exchange 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, in general, to protect investors and the public interest. The Commission believes that providing the Cap could provide the Exchange with a system protection tool to address the potential risk that a single OTP could—either intentionally or inadvertently– utilize the entire complex order table, effectively shutting out all other OTPs' Electronic Complex Orders from the Exchange for the remainder of the trading day. By disabling the submission of Electronic Complex Orders of a single OTP that has exceeded the Cap, the Cap should allow the Exchange to accommodate Electronic Complex Orders from all other OTPs, thereby helping to ensure efficient functionality of the complex order table and the protection of investors and the public interest. In approving this proposed rule change, the Commission notes that the Exchange represented that under normal operating conditions, the combined Electronic Complex Orders of all OTPs do not exceed 40% of the complex order table.[12] Therefore, the Exchange believes that setting the Cap for a single OTP at 60% would allow 40% of the complex order table—which is typically sufficient to accommodate all OTP's Electronic Complex Orders—to remain accessible to the balance of OTPs and would not unfairly deny these OTPs access to the market.[13]

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether Amendment No. 2 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–2013–115 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NYSEArca–2013–115. 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 publicly available. All submissions should refer to File Number SR–NYSEArca–2013–115 and should be submitted on or before January 29, 2014.

V. Accelerated Approval of Proposed Rule Change, as Modified by Amendment Nos. 1 and 2

As proposed, the proposed rule change provided that, unless determined otherwise by the Exchange and announced to OTPs via Trader Update, the specified percentage (*i.e.,* ''n%'') will be no less than 60%, and ''n%-x'' will be no less than 40%. Amendment No. 2 amended the proposed rule change by removing the language in the proposal that gives the Exchange discretion to adjust the specified percentage (*i.e.,* ''n%'') to an amount less than 60% and ''n%-x'' to an amount less than 40%. By removing this discretion, Amendment No. 2 reduces potential uncertainty about the application of the proposed rule change. Accordingly, the Commission finds good cause, pursuant to Section 19(b)(2) of the Act,[14] for approving the proposed rule change, as modified by Amendment Nos. 1 and 2, prior to the 30th day after the date of publication of notice in the **Federal Register**.

VI. Conclusion

It is therefore ordered, pursuant to Section 19(b)(2) of the Act[15] that the proposed rule change (SR–NYSEArca–2013–115), as modified by Amendment Nos. 1 and 2, be, and hereby is, approved on an accelerated basis.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[16]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–00065 Filed 1–7–14; 8:45 am]

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[9] For example, if an OTP submits an Electronic Complex Order that, once accepted, breaches the Cap, the Exchange will accept that order in its entirety and then will reject all subsequent Electronic Complex Orders from that OTP for the remainder of the trading day.

[10] In approving the proposed rule changes, the Commission has considered their impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[11] 15 U.S.C. 78f(b)(5).

[12] *See* Notice, *supra* note 4 at 68114. The Commission also notes that the Exchange represented that a single OTP would only exceed the Cap (or receive a warning of a near breach) in the event of a bona fide problem (*e.g.,* a system error or malfeasance). *See id.*

[13] *See* Notice, *supra* note 4 at 68115.

[14] 15 U.S.C. 78s(b)(2).

[15] 15 U.S.C. 78f(b)(2).

[16] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–71225; File No. SR–C2–2013–042]

Self-Regulatory Organizations; C2 Options Exchange, Incorporated; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change Relating to the Exchange's Fee Schedule

January 2, 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 December 24, 2013, C2 Options Exchange, Incorporated (the ''Exchange'' or ''C2'') filed with the Securities and Exchange Commission (the ''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend the Options Regulatory Fee. The text of the proposed rule change is available on the Exchange's Web site (*http://www.c2exchange.com/Legal/*), at the Exchange's Office of the Secretary, and at the Commission's Public Reference Room.

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, the Exchange included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange has reevaluated the current amount of the Options Regulatory Fee (''ORF'') in connection with its annual budget review. In light of a recent reevaluation of regulatory costs and the expected volume levels for 2014, the Exchange proposes to decrease the ORF from $.0017 (effective January 1, 2014) to $.0012 per contract. This proposed fee change would be operative on February 1, 2014.

The ORF is assessed by the Exchange to each Permit Holder for all options transactions executed or cleared by the Permit Holder that are cleared by The Options Clearing Corporation (''OCC'') in the customer range (i.e., transactions that clear in a customer account at OCC) regardless of the marketplace of execution. In other words, the Exchange imposes the ORF on all customer-range transactions executed by a Permit Holder, even if the transactions do not take place on the Exchange.[3] The ORF also is charged for transactions that are not executed by a Permit Holder but are ultimately cleared by a Permit Holder. In the case where a Permit Holder executes a transaction and a different Permit Holder clears the transaction, the ORF is assessed to the Permit Holder who executed the transaction. In the case where a non-Permit Holder executes a transaction and a Permit Holder clears the transaction, the ORF is assessed to the Permit Holder who clears the transaction. The ORF is collected indirectly from Permit Holders through their clearing firms by OCC on behalf of the Exchange.

The ORF is designed to recover a material portion of the costs to the Exchange of the supervision and regulation of Permit Holder customer options business, including performing routine surveillances, investigations, examinations, financial monitoring, as well as policy, rulemaking, interpretive and enforcement activities. The Exchange believes that revenue generated from the ORF, when combined with all of the Exchange's other regulatory fees and fines, will cover a material portion, but not all, of the Exchange's regulatory costs. The Exchange notes that its regulatory responsibilities with respect to Permit Holder compliance with options sales practice rules have largely been allocated to FINRA under a 17d–2 agreement. The ORF is not designed to cover the cost of that options sales practice regulation.

The Exchange will monitor the amount of revenue collected from the ORF to ensure that it, in combination with its other regulatory fees and fines, does not exceed the Exchange's total regulatory costs. If the Exchange determines regulatory revenues exceed regulatory costs, the Exchange will adjust the ORF by submitting a fee change filing to the Commission. The Exchange notifies Permit Holders of adjustments to the ORF via regulatory circular.

2. Statutory Basis

The Exchange believes the proposed rule change is consistent with the Securities Exchange Act of 1934 (the ''Act'') and the rules and regulations thereunder applicable to the Exchange and, in particular, the requirements of Section 6(b) of the Act.[4] Specifically, the Exchange believes the proposed rule change is consistent with Section 6(b)(4) of the Act,[5] which provides that Exchange rules may provide for the equitable allocation of reasonable dues, fees, and other charges among its Permit Holders and other persons using its facilities. Additionally, the Exchange believes the proposed rule change is consistent with the Section 6(b)(5) [6] requirement that the rules of an exchange not be designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

The Exchange believes the proposed fee change is reasonable because it would more effectively help the Exchange offset regulatory expenses and would not result in total regulatory revenue exceeding total regulatory costs. The Exchange believes the ORF is equitable and not unfairly discriminatory in that it is charged to all Permit Holders on all their transactions that clear in the customer range at the OCC. Moreover, the Exchange believes the ORF ensures fairness by assessing higher fees to those Permit Holders that require more Exchange regulatory services based on the amount of customer options business they conduct. Regulating customer trading activity is much more labor intensive and requires greater expenditure of human and technical resources than regulating non-customer trading activity, which tends to be more automated and less labor-intensive. As a result, the costs associated with administering the customer component of the Exchange's overall regulatory

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] Exchange rules require each Permit Holder to record the appropriate account origin code on all orders at the time of entry in order to allow the Exchange to properly prioritize and route orders and assess transaction fees pursuant to the rules of the Exchange and report resulting transactions to the OCC. C2 order origin codes are defined in C2 Regulatory Circular RG13–015. The Exchange represents that it has surveillances in place to verify that Trading Permit Holders mark orders with the correct account origin code.

[4] 15 U.S.C. 78f(b).

[5] 15 U.S.C. 78f(b)(4).

[6] *Id.* [sic]

program are materially higher than the costs associated with administering the non-customer component (e.g., Permit Holder proprietary transactions) of its regulatory program.[7]

B. Self-Regulatory Organization's Statement on Burden on Competition

C2 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. The proposed rule change is not designed to address any competitive issues. Rather, the proposed rule change is designed to help the Exchange to adequately fund its regulatory activities while seeking to ensure that total regulatory revenues do not exceed total regulatory costs.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The Exchange neither solicited nor received comments on the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A) of the Act[8] and paragraph (f) of Rule 19b–4[9] thereunder. At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission will institute proceedings to determine whether the proposed rule change should be approved or disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov.* Please include File Number SR–C2–2013–042 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–C2–2013–042. 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 publicly available. All submissions should refer to File Number SR–C2–2013–042 and should be submitted on or before January 29, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[10]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–00069 Filed 1–7–14; 8:45 am]

BILLING CODE 8011–01–P

[7] If the Exchange changes its method of funding regulation or if circumstances otherwise change in the future, the Exchange may decide to modify the ORF or assess a separate regulatory fee on Permit Holder proprietary transactions if the Exchange deems it advisable.

[8] 15 U.S.C. 78s(b)(3)(A).

[9] 17 CFR 240.19b–4(f).

[10] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–71226; File No. SR–NASDAQ–2013–164]

Self-Regulatory Organizations; The NASDAQ Stock Market LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change to Further Describe the Application of Fees Assessed for Connectivity to the Carteret Test Environment under Rule 7030(d)

January 2, 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 December 23, 2013, The NASDAQ Stock Market LLC (''NASDAQ'' or the ''Exchange'') filed with the Securities and Exchange Commission (''Commission'') a proposed rule change as described in Items I and II below, which Items have been prepared by the Exchange. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of the Substance of the Proposed Rule Change

The Exchange proposes a proposed rule change to further describe the application of fees assessed pursuant to Rule 7030(d)(1)(C).

The text of the proposed rule change is below. Proposed new language is italicized. Proposed deletions are in brackets.

* * * * *

7030. Other Services

(a)–(c) No change.

(d) Nasdaq Testing Facilities

Nasdaq operates two testing environments. One is located in Ashburn, Virginia and the other in Carteret, New Jersey. Unless otherwise noted, reference to the ''Nasdaq Testing Facility'' or ''NTF'' applies to both environments.

(1) The following fees are assessed for access to the Nasdaq Testing Facility:

(A) Subscribers that conduct tests of the computer-to-computer interface (CTCI) and the Financial Information Exchange (FIX) interface to ACT and ACES access protocols through the Nasdaq Testing Facility (NTF) shall pay the following charges:

$285/hour	For Active Connection testing during the normal operating hours of the NTF;

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

No Charge $333/hour	For Idle Connection testing; For Active Connection testing at all times other than the normal operating hours of the NTF.

(B) Subscribers that conduct tests of all Nasdaq access protocol connections not included in paragraph (A) above or of market data vendor feeds through the Nasdaq Testing Facility shall pay $300 per port, per month.

(C) Subscribers to the Nasdaq Testing Facility located in Carteret, New Jersey shall pay a fee of $1,000 per hand-off, per month for connection to the NTF. The hand-off fee includes either a 1Gb or 10Gb switch port and a cross connect to the NTF. Subscribers shall also pay a one-time installation fee of $1,000 per hand-off, which is waived for all installations ordered prior to March 31, 2014.

The connectivity provided under this rule also provides connectivity to the other test environments of NASDAQ OMX BX, Inc. and NASDAQ OMX PHLX LLC.

(2)–(6) No change.

* * * * *

II. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

In its filing with the Commission, NASDAQ included statements concerning the purpose of, and basis for, the proposed rule change and discussed any comments it received on the proposed rule change. The text of those statements may be examined at the places specified in Item IV below. The Exchange has prepared summaries, set forth in sections A, B, and C below, of the most significant parts of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange is proposing to amend the Rule 7030(d) to more fully describe the application of the newly-adopted fee [3] assessed for direct connectivity to the Testing Facility [4] test environment located in Carteret, New Jersey (''Carteret''). The Testing Facility provides subscribers with a virtual Exchange System test environment that closely approximates the production environment and on which they may test their automated systems that integrate with the Exchange. The Exchange recently developed a test environment located in Carteret that provides Exchange equity trade testing functionality. The new test environment was developed together with equity test environments of the Exchange's sister exchanges, NASDAQ OMX BX, Inc. and NASDAQ OMX PHLX LLC, also located at Carteret, New Jersey (collectively with NASDAQ, the ''Equity Markets'').

The Exchange is proposing to add language to Rule 7030(d)(1)(C) that was erroneously omitted when the fee was originally adopted.[5] The new rule text explains that a firm that is a member of more than one of the Equity Markets may access the test environments of each of the Equity Markets of which it is a member through a single connectivity subscription under the rule. The Exchange notes that each of the Equity Markets has identical installation and hand-off fees for Carteret connectivity and these fees relate to the physical connection to the hardware infrastructure that houses all three test environments of the Equity Markets. Members of the Equity Markets must separately pay port fees to connect to the individual test environments of the Equity Markets of which it is a member within the hardware infrastructure housing them.[6] Therefore, a firm that is a member of multiple Equity Markets is not charged the Carteret connectivity fees for a hand-off under each of the identical rules of such markets, but rather is assessed a single market's Carteret connectivity fees. Consequently, a member firm of NASDAQ using the Carteret test environment may be assessed the connectivity fees under another Equity Markets' rules of which it is a member, yet pay the NASDAQ port fee to connect to the Exchange's test environment. Similarly, a member firm may subscribe to Carteret connectivity under NASDAQ Rule 7030(d)(1)(C) and not have an obligation to pay the same fee under the rules of the other Equity Markets of which it is a member, but have an obligation to pay those markets' port fees. The Exchange notes that, in adopting the identical fee for Carteret connectivity, NASDAQ OMX BX, Inc. included rule text consistent with the rule text proposed herein.[7] Accordingly, the Exchange is adding rule text to Rule 7030(d)(1)(C) to reflect that the connectivity provided by the rule also provides access to the test environments of NASDAQ OMX BX, Inc. and NASDAQ OMX PHLX LLC.

2. Statutory Basis

The Exchange believes that its proposal is consistent with Section 6(b) of the Act [8] in general, and with Section 6(b)(5) of the Act,[9] in particular. The Exchange believes the proposal furthers the objectives of Section 6(b)(5) of the Act [10] in that it is designed to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism of a free and open market and a national market system, and, in general to protect investors and the public interest and is not designed to permit unfair discrimination between customer, issuers, brokers and dealers. The Exchange is proposing to add clarifying language to the rule, which was erroneously omitted when the rule was adopted and further describes the application of the rule. Moreover, the proposed new rule text is consistent with the identical rule of BX and how fees are assessed under that rule. Accordingly, the Exchange believes that it is consistent with the protection of investors and the public interest to avoid potential market participant confusion that may be caused by the omission of the proposed rule text.

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. The proposed rule change clarifies how fees will be assessed to a firm that is a member of more than one of the Equity Markets and makes clear that a member firm may gain access to the test environments of the other Equity Markets through a subscription under the rule. Members of multiple Equity Markets are assessed the same fee for Carteret connectivity and must pay the port fees of each of the Equity Markets to gain access to such markets' test environments. As a consequence, the Exchange does not believe that the proposed rule change is impactful to competition in any respect.

[3] *See* Securities Exchange Act Release No. 70851 (November 13, 2013), 78 FR 69485 (November 19, 2013) (SR–NASDAQ–2013–137).

[4] *See http://www.nasdaqtrader.com/Trader.aspx?id=TestingFacility* for a description of the Testing Facility.

[5] *Supra* note 3.

[6] NASDAQ Rule 7030(d)(1)(B), Phlx Pricing Schedule Chapter VIII Testing Facilities subparagraph (a), and BX Rule 7030(d)(1).

[7] *See* Securities Exchange Act Release No. 71035 (December 11, 2013), 78 FR 76344 (December 17, 2013) (SR–BX–2013–058).

[8] 15 U.S.C. 78f(b).

[9] 15 U.S.C. 78f(b)(5).

[10] *Id.*

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The Exchange has filed the proposed rule change pursuant to Section 19(b)(3)(A) of the Act [11] and Rule 19b–4(f)(6) [12] thereunder. Because the foregoing proposed rule change does not: (i) Significantly affect the protection of investors or the public interest; (ii) impose any significant burden on competition; and (iii) become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A) of the Act [13] and subparagraph (f)(6) of Rule 19b–4 thereunder.[14]

A proposed rule change filed under Rule 19b–4(f)(6) [15] normally does not become operative prior to 30 days after the date of the filing. However, pursuant to Rule 19b–4(f)(6)(iii),[16] 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. The Exchange notes that such waiver will allow the Exchange to immediately add language to its rule text that was incorrectly omitted from a previous rule change, thereby clarifying its rules and avoiding potential market participant confusion.[17] The Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest as the proposal is designed to avoid potential investor confusion regarding the Exchange's rules and provide clarification to the public. For these reasons, the Commission hereby waives the 30-day operative delay and designates the proposal operative upon filing.[18]

At any time within 60 days of the filing of the proposed rule change, the Commission summarily may temporarily suspend such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule 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–NASDAQ–2013–164 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NASDAQ–2013–164. 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 offices 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–2013–164, and should be submitted on or before January 29, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[19]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–00070 Filed 1–7–14; 8:45 am]

BILLING CODE 8011–01–P

[11] 15 U.S.C. 78s(b)(3)(A).

[12] 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 text of the proposed rule change, at least five business days prior to the date of filing of the proposed rule change, or such shorter time as designated by the Commission. The Exchange has satisfied this requirement.

[13] 15 U.S.C. 78s(b)(3)(A).

[14] 17 CFR 240.19b–4(f)(6).

[15] *Id.*

[16] 17 CFR 240.19b–4(f)(6)(iii).

[17] *See* SR–NASDAQ–2013–164, Item 7.

[18] For purposes only of waiving the 30-day operative delay, the Commission has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[19] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–71223; File No. SR–CBOE–2013–109]

Self-Regulatory Organizations; Chicago Board Options Exchange, Incorporated; Order Approving a Proposed Rule Change Relating to Market-Maker Appointment Cost Rebalances

January 2, 2014.

I. Introduction

On November 1, 2013, Chicago Board Options Exchange, Incorporated (''Exchange'' or ''CBOE'') filed with the Securities and Exchange Commission (''Commission''), pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'') [1] and Rule 19b–4 thereunder,[2] a proposed rule change to amend its rules regarding Market-Maker appointment cost rebalances. The proposed rule change was published for comment in the **Federal Register** on November 19, 2013.[3] The Commission received no comment letters on the proposed rule change. This order approves the proposed rule change.

II. Description of the Proposed Rule Change

The Exchange is proposing to amend its rules regarding Market-Maker appointment cost rebalances. According to the Exchange, appointments to act as a Market-Maker ''cost'' different

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 70856 (November 13, 2013), 78 FR 69491 (''Notice'').

amounts for different classes (with no classes costing more than 1.0).[4] The Exchange places options classes into different tiers, with all the classes in a certain tier costing the same amount per appointment.[5] Each Trading Permit held by a Market-Maker has an appointment credit of 1.0. For each Trading Permit the Market-Maker holds, the Market Maker may select any combination of Hybrid classes and Hybrid 3.0 classes, whose aggregate appointment cost does not exceed 1.0.[6]

Currently, on a quarterly basis, the Exchange may rebalance the tiers into which different classes fall, meaning that the Exchange can elect to move a class from one tier to another (with that class' corresponding appointment cost changing). The Exchange proposes to memorialize in proposed CBOE Rule 8.3(c)(iv) that the Exchange will announce any rebalances at least ten business days before the rebalance takes effect.[7] Under the proposal, such rebalances will be announced to Trading Permit Holders (''TPHs'') via Regulatory Circular.

When the Exchange effects a rebalancing (*i.e.,* changes the appointment cost tier for a certain class of options), the class is assigned the appointment cost of that new tier. Upon such rebalancing, each Market-Maker with a Virtual Trading Crowd (''VTC'') appointment[8] will be required to hold the appropriate number of Trading Permits reflecting the revised appointment costs of the Hybrid classes constituting the Market-Maker's appointment. Accordingly, when classes are rebalanced, the sum of a Market-Maker's appointment costs cannot exceed the number of Trading Permits that a Market-Maker holds. Market-Makers manage their own appointments through an online appointment system. The system displays the relevant appointment costs for each class, thereby facilitating the ability of a Market-Maker to manage its committed and available appointment credits.

The Exchange proposes to add language to CBOE Rule 8.3(c)(iv) to address situations in which a Market-Maker fails to adjust his or her appointments and, as a result, the sum of the Market-Maker's appointment costs otherwise would exceed the available appointment credits based on the number of Trading Permits the Market-Maker holds. The proposed new language states: ''[i]f a Market-Maker with a VTC appointment holds a combination of appointments whose aggregate revised appointment cost is greater than the number of Trading Permits that Market-Maker holds, the Market-Maker will be assigned as many Trading Permits as necessary to ensure that the Market-Maker no longer holds a combination of appointments whose aggregate revised appointment cost is greater than the number of Trading Permits that Market-Maker holds.'' In the event that a Market-Maker's appointment costs exceed his or her available assignment credits as the result of a reassignment of appointment costs by the Exchange, and the Exchange needs to allocate another trading permit or permits to the Market-Maker, then the Exchange also will assess the Market-Maker the corresponding Trading Permit fees for the additional Trading Permit(s).[9]

III. Discussion and Commission's Findings

After careful review, the Commission finds that the proposed rule change is consistent with the requirements of the Act and the rules and regulations thereunder applicable to a national securities exchange.[10] In particular, the Commission finds that the proposed rule change is consistent with Section 6(b)(5) of the Act,[11] which requires, among other things, that the rules of a national securities exchange 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, and not be designed to permit unfair discrimination between customers, issuers, brokers, or dealers. The Commission also finds that the proposed rule change is consistent with Section 6(b)(1) of the Act,[12] which provides that the Exchange be organized and have the capacity to be able to carry out the purposes of the Act and to enforce compliance by its members and persons associated with its members, with the Act, the rules and regulations thereunder, and the rules of the Exchange.

The proposed rule change is designed to allow the Exchange to avoid a situation where a Market-Maker has an aggregate appointment cost that exceeds the available appointment credits that the Market-Maker holds based on the trading permits that he or she possesses. The Exchange argues that such a situation would constitute an unfair advantage in favor of that Market-Maker.[13] The Exchange argues that, by preventing such situations, the proposed rule change may remove impediments to and perfect the mechanism of a free and open market system. In its filing, the Exchange noted that it does not have the ability to adjust the VTC appointments of a Market-Maker whose aggregate appointment costs exceeds his or her available appointment credits. Even if it did have such ability, rectifying an appointment cost deficit by removing one or more of a Market-Maker's appointments would remove a source of liquidity and thus have the potential to negatively affect market quality in a particular class on CBOE. Further, allowing a Market-Maker to exceed his or her appointment costs would amount to unfair discrimination and provide a competitive advantage over other Market-Makers who stayed within their available appointment credits. As an alternative to incurring the expense of an additional trading permit, a Market-Maker could, in response to an increase in tier appointment costs by CBOE, adjust its appointments on its own initiative.

In addition, the revised rule would codify the Exchange's current practice of notifying TPHs at least ten business days before effecting Market-Maker class tier rebalances, which could potentially affect their fees if they are required to purchase additional trading permits. It also would enable the Exchange to adjust the VTC appointments of a Market-Maker whose aggregate appointment cost exceeds the number of trading permits that the Market-Maker holds and charge the Market-Maker for

[4] *See id.* at 69491.

[5] For example, all the classes in tier B cost 0.05 per class appointment, all the classes in tier E cost .01 per class appointment. *See id.*

[6] *See* CBOE Rule 8.3(c)(iv).

[7] It is the Exchange's current practice to announce such rebalances more than ten business days prior to taking effect, but this practice is not codified in CBOE's rules. *See* Notice, *supra* note 3, at 69491.

[8] A VTC appointment allows a Market-Maker to quote electronically in a class.

[9] For example, the Exchange described a situation in which a Market-Maker's aggregate appointment cost for the classes for which it holds Market-Maker appointments prior to a rebalancing is 4.90 and the Market-Maker holds five Trading Permits (*i.e.,* a total of 5.0 credits). The Exchange then rebalances the appointment costs of classes and announces such rebalancing at least ten days prior to the rebalancing takes effect. Upon this rebalancing taking effect, the Market-Maker's appointment cost will now be 5.40. If the Market-Maker does not adjust its appointments prior to such rebalancing taking effect, then the Exchange will simply assign that Market-Maker a sixth Market-Maker Trading Permit (for a total of 6.0 credits) to cover the Market-Maker's aggregate appointment costs . The Exchange also will begin to bill the Market-Maker for the cost of the additional sixth permit. *See id.*

[10] In approving this proposed rule change, the Commission notes that it has considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

[11] 15 U.S.C. 78f(b)(5).

[12] 15 U.S.C. 78f(b)(1).

[13] *See* Notice, *supra* note 3, at 69492.

the additional permit(s). The Exchange states that this proposal would allow the Exchange to avoid the resource-intensive process of instituting regulatory proceedings against these Market-Makers who fall out of compliance with the Exchange's rule.[14] The Commission believes that CBOE's proposal is consistent with CBOE's responsibility to be organized and have the capacity to be able to enforce compliance by the Exchange's members with its rules, and is designed to allow CBOE to expeditiously and efficiently maintain a level playing field among its Market-Makers with respect to appointment costs following a rebalancing of such costs by the Exchange.

IV. Conclusion

It is therefore ordered, pursuant to Section 19(b)(2) of the Act,[15] that the proposed rule change (SR–CBOE–2013–109) be, and it hereby is, approved.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[16]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–00067 Filed 1–7–14; 8:45 am]

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[14] *See* Notice, *supra* note 3, at 69491.

[15] 15 U.S.C. 78s(b)(2).

[16] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–71224; File No. SR–FINRA–2013–054]

Self-Regulatory Organizations; Financial Industry Regulatory Authority, Inc.; Notice of Filing of a Proposed Rule Change Relating to a Capacity Management Plan

January 2, 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 December 24, 2013, Financial Industry Regulatory Authority, Inc. (''FINRA'') filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by FINRA. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

I. Self-Regulatory Organization's Statement of the Terms of the Substance of the Proposed Rule Change

FINRA is proposing to adopt a new FINRA Capacity Management Plan (''Plan'') for the Alternative Display Facility (''ADF'') and amend the ADF Trading Center Certification Record (''Certification'') to, among other things, require ADF Trading Centers to comply with the Plan.

A copy of the Plan was filed as Exhibit 3a. A copy of the revised Certification was filed as Exhibit 3b. The text of the proposed rule change is available on FINRA's Web site at *http://www.finra.org,* at the principal office of FINRA 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, FINRA included statements concerning the purpose of and basis for the proposed rule change and discussed any comments it received on the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. FINRA has prepared summaries, set forth in sections A, B, and C below, of the most significant aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The ADF is a quotation collection and trade reporting facility that provides ADF Market Participants (i.e., ADF-registered market makers or electronic communications networks (''ECNs''))[3] the ability to post quotations, display orders and report transactions in NMS stocks[4] for submission to the Securities Information Processors (''SIPs'') for consolidation and dissemination to vendors and other market participants. In addition, the ADF delivers real-time data to FINRA for regulatory purposes, including enforcement of requirements imposed by Regulation NMS.[5]

To become an ADF Market Participant, a member must apply to FINRA, which includes certifying the member's good standing with FINRA and demonstrating compliance with the net capital and other financial responsibility provisions of the Act.[6] Before displaying quotations or orders on the ADF, an ADF Market Participant that is an ''ADF Trading Center''[7] must also execute and comply with a Certification Record to certify the ADF Trading Center's compliance efforts with its obligations under Regulation NMS.[8]

Regulatory developments, such as the SEC's adoption of Regulation NMS in 2005, have resulted in a dramatic increase in quote and trade volume in the National Market System. The securities markets have experienced significant changes, evolving to a larger number and variety of trading centers that are almost completely automated, with sophisticated, rapid and interconnected systems. As a result of this increase in volume, self-regulatory organizations (''SROs'') and trading centers generally have sought to adopt increasingly robust capacity management plans to ensure that they are capable of processing quote and trade data during volume peaks.

In addition, SROs have found it necessary to develop capacity management plans to mitigate the potential of being penalized for overrunning their volume projections submitted to the consolidated data plans. For example, the Consolidated Tape Association Plan (''CTA Plan'') and the Consolidated Quotation Plan (''CQ Plan''; together, ''CTA/CQ Plans''), which serve as the consolidated data plans for securities listed on the New York Stock Exchange, BATS, NYSE Arca, NYSE MKT and other regional exchange-listed securities,[9] currently enforce a strict ''pay-for-capacity'' methodology that includes monetary penalties for capacity overruns.[10] Under this approach, SROs submit volume

[3] *See* Rule 6220(a)(3).

[4] *See* 17 CFR 242.600.

[5] *See* 17 CFR 242.600.

[6] *See* Rule 6271(b). FINRA has submitted a proposed rule change to amend the ADF rules to, among other things, assess an ADF Deposit Amount on ADF Market Participants. *See* Securities Exchange Act Release No. 70048 (July 26, 2013), 78 FR 46652 (August 1, 2013) (SR–FINRA–2013–031).

[7] An ''ADF Trading Center'' is a Registered Reporting ADF Market Maker or Registered Reporting ADF ECN that is a ''Trading Center,'' as defined in Rule 600(b)(78) of SEC Regulation NMS, and that is certified to display its quotations or orders through the ADF. *See* Rule 6220(a)(4); *see also* 17 CFR 242.600(b)(78).

[8] *See* Rules 6220(a)(5), 6250(a)(7); NASD Notice to Members 06–67 (November 2006); *see also* SR–NASD–2006–091, Amendment No. 3, Exhibit 3.

[9] The CTA Plan governs the collection and dissemination of last sale price information for non-NASDAQ listed securities, while the CQ Plan governs the collection and dissemination of bid/ask quotation information for listed securities.

[10] *See* Exhibit A to the CTA Plan (October 1, 2013 composite), available at *https://cta.nyxdata.com/CTA* (Capacity Planning Process for The Consolidated Tape System); *see also* Exhibit A to the CQ Plan (October 1, 2013 composite), available at *https://cta.nyxdata.com/CTA.*

projections for the coming planning period and are held to those projections. SROs that overrun their projections are subject to penalties that increase incrementally based on the number of trading days within a calendar month that the SRO overran its submitted projections and the amount by which the SRO exceeded its submitted projections. In some cases, based on the number of trading days that projections have been exceeded, SROs may be subject to mandatory commitments to buy additional capacity going forward.[11]

Similar to the approach of the CTA/CQ Plans to capacity planning, FINRA is proposing to adopt the Plan for those FINRA members that opt to utilize the ADF for quoting and trade reporting. ADF Trading Centers would be required to agree to abide by the Plan as part of the Certification that ADF Trading Centers are required to execute and comply with to quote on and report trades to the ADF.[12] The details of the Plan are set forth below.

Definitions

The Plan defines ''CTA Securities'' as securities subject to the Consolidated Tape Association Plan (i.e., securities listed on the New York Stock Exchange, BATS Exchange Inc., NYSE MKT LLC or NYSE Arca LLC). The Plan defines ''UTP Securities'' as securities subject to the Unlisted Trading Privileges Plan (i.e., securities listed on the Nasdaq Stock Market, LLC).[13] Finally, the Plan defines ''Certified Capacity'' as the maximum level of data (by message rate and message type) an ADF Trading Center is certified to submit to the ADF Platform following the quarterly certification volume test conducted by FINRA.

ADF Trading Center Capacity Certification

Prior to commencing quoting or trade reporting through the ADF, the Plan requires that each ADF Trading Center complete an initial ADF Trading Center Capacity Certification process.[14] As part of this process, an ADF Trading Center must test its connectivity to the ADF with FINRA Product Management. FINRA will provide estimates for the costs of such testing, and, upon receipt of these estimates, the ADF Trading Center may request in writing that FINRA proceed with connectivity testing. Regardless of whether an ADF Trading Center ultimately is certified and becomes an active ADF Trading Center, the ADF Trading Center will be responsible for the testing costs and will be invoiced accordingly.

The Plan also requires each ADF Trading Center to submit volume projections for current and future peak data reporting levels on a quarterly basis, and on demand from FINRA. ADF Trading Centers must submit volume projections separately for CTA Securities and UTP Securities, and they must project their volume for quotations, media trade reports, total trade reports, and order reports. An ADF Trading Center is not certified to submit quote, trade or order reporting data at its requested level simply because it has submitted its initial or final volume projections. Rather, prior to submitting quote, trade and order reporting data at its projected volume levels, FINRA staff may require an ADF Trading Center to successfully complete a test at the projected volume levels.

Capacity Projection Submission

As part of both the initial certification process, and as part of its ongoing utilization of the ADF, an ADF Trading Center is required to provide quarterly volume projections that accurately reflect its anticipated capacity requirements for the next two quarters in order for FINRA to assess ADF system infrastructure requirements. Such anticipated capacity requirements must be submitted on the ADF Trading Center Volume Projections Form (''Form'')[15] as required by FINRA Product Management and must be received by FINRA at least 45 calendar days prior to the end of each calendar quarter for the next two calendar quarters. Submissions are due by certain specified due dates. If a submission is not received by the specified due date, FINRA will make assumptions for ADF Trading Center projections based on prior certified activity levels. Certified capacities are established separately for UTP Securities and for CTA Securities in the following categories: (1) Quotations; (2) Media Trade Reports; (3) Total Trade Reports (i.e., media and non-media); and (4) Order Reports. This traffic must be provided on both a messages-per-second[16] and transactions-per-day basis, on both a projected average day and on a projected peak day. The ADF Trading Center must also specify on the Form, for both CTA and UTP securities, the number of securities it will trade, the average number of securities it will trade, and the number of securities in which it will make a market (if applicable).

As set forth in the Plan, an ADF Trading Center submits its projections for the next two calendar quarters. Once an ADF Trading Center has submitted its projections for the following quarter, it may not adjust those projections; however, an ADF Trading Center will not be locked into its second quarter projections until the commencement of the planning process for that quarter, e.g., 60 calendar days before the end of the first quarter. FINRA will allow each ADF Trading Center to increase its projections for the second quarter, if necessary. An ADF Trading Center may also lower its projections by up to 10% for the second calendar quarter. Each ADF Trading Center will be subject to an Excess Capacity Usage Fee schedule (''Excess Fee'') and a Shortfall Capacity Usage Fee schedule (''Shortfall Fee''), which are discussed in greater detail below.

The reason for limiting the extent to which an ADF Trading Center may lower its capacity projection for the second calendar quarter for quote and trade data is attributable to the manner in which FINRA incurs costs related to the NMS data plans, including the direct purchase of capacity pursuant to the CTA/CQ Plans.[17] FINRA configures servers to support the capacity projections from ADF Trading Centers and purchases corresponding capacity from the SIPs. With respect to the CTA/CQ Plans, once FINRA has purchased capacity from the SIP, it cannot divest itself of such capacity unless there is another participant willing to acquire that capacity. By allowing ADF Trading Centers to lower their capacity projections by up to 10% for the second quarter, FINRA is providing ADF Trading Centers with some flexibility to formulate their capacity projections

[11] *Id.*

[12] If a firm is only reporting trades to the ADF and is not quoting on the ADF, the firm is not an ''ADF Trading Center'' and is not required to complete the Certification.

[13] For purposes of this proposal, the CTA/CQ Plans and the Unlisted Trading Privileges Plan (''UTP Plan'') may be collectively referred to as the ''NMS data plans.''

[14] Each ADF Trading Center also is required to complete an annual recertification.

[15] The ADF Trading Center Volume Projections Form is Attachment A to the Plan.

[16] FINRA notes that the SIPs recently adopted a 100 millisecond projected peak capacity planning metric, and so FINRA reserves the ability to change this time metric through a proposed rule change to be filed with the Commission.

[17] Currently, FINRA directly purchases capacity under the CTA/CQ Plans for quote and trade reporting. FINRA indirectly pays for capacity under the UTP Plan in connection with quote and trade reporting, as it pays an administrator fee and a processor fee under the UTP Plan that is deducted from the Plan's gross revenues, with FINRA receiving any distributions from the Plan's net revenues. Upon SEC approval of the relevant pending amendment to the UTP Plan, *see* Securities Exchange Act Release No. 62021 (April 30, 2010), 75 FR 27010 (May 13, 2010) (File No. S7–24–89), FINRA will also directly purchase capacity under the UTP Plan.

while helping to ensure that ADF Trading Centers provide realistic capacity projections, thus defraying potential costs to FINRA. Similarly, although FINRA does not purchase SIP capacity for order reporting information, it does incur costs in purchasing the necessary hardware and software to support the intake and storage of such information.

Capacity Planning Schedule

The Plan sets forth a schedule to ensure that ADF Trading Centers provide timely and accurate volume projections which will enable FINRA to make an accurate assessment of system and capacity requirements. For example, on the first trading day of the second month of the planning cycle, FINRA will notify ADF Trading Centers via email that initial volume projections on the ADF Trading Center Volume Projections Form are due. ADF Trading Centers have ten business days following the initial FINRA notification to provide initial volume projections via email on the ADF Trading Center Volume Projections Form. Between the tenth and twentieth business day following the initial FINRA notification, FINRA advises ADF Trading Centers of the respective ADF Trading Center's Available Capacity based on the ADF Trading Center's projections and requests final volume projections. FINRA will also advise ADF Trading Centers of any necessary ADF system upgrades required to accommodate their volume requests. Between the twentieth and twenty-fifth business day following the initial FINRA notification, ADF Trading Centers are required to give their final volume projections to FINRA via email on the ADF Trading Center Volume Projections Form. To the extent that a capacity increase is required, the system test will be completed between the twentieth and fortieth business days following the initial FINRA request for projections.[18]

Capacity Allocations

As set forth in the Plan, if an ADF Trading Center requests a certain amount of capacity, FINRA will honor such request and will build out capacity to support the ADF Trading Center's peak projected capacity requirements. Once an ADF Trading Center has formally requested capacity, the Plan provides that such request may not be rescinded. A request does not mean, however, that the ADF Trading Center is entitled to submit to the projected level; rather, each ADF Trading Center must still partake in quarterly volume tests before it is certified to its requested volume level.

The Plan also provides that an ADF Trading Center is only authorized to submit increased volume after conducting a capacity test and receiving written notice from FINRA that the ADF Trading Center is certified for operation at the specified level.

Finally, if an ADF Trading Center ceases posting quotes on the ADF or stops reporting trades to the ADF and becomes inactive (either under Rule 6250(g) or by voluntary withdrawal), the Plan provides that such Trading Center will be deemed to have surrendered any capacity to which it was previously certified. The ADF Trading Center is still liable for any Capacity Usage Fees it may have incurred while active.

Extraordinary Upgrades

To the extent that an ADF Trading Center's volume overrun (either in message volume by category or in message per second throughput) threatens, in FINRA's sole discretion, its ability to meet its regulatory obligations, the Plan provides that FINRA has the right to make mid-quarter extraordinary system upgrades to accommodate higher message volume or higher message per second throughput. The costs for such new infrastructure investment will be borne by the ADF Trading Center that has exceeded its Certified Capacity, or, if multiple ADF Trading Centers have exceeded their Certified Capacity, will be allocated among such ADF Trading Centers. In all such instances, FINRA will provide notice to the affected ADF Trading Center(s) that FINRA is taking such actions.

Notwithstanding FINRA's ability to implement a mid-quarter extraordinary system upgrade, to the extent that ADF message volume materially exceeds certified levels of operation, as determined by FINRA staff, the Plan provides that FINRA technical staff may reconfigure the ADF connection to ensure that data levels stay at or below reasonable levels of operation. Such reconfiguration may occur on an intra-day basis in proportion to the extent to which the higher ADF message volume threatens FINRA's system stability and/or the ability of FINRA to meet its regulatory obligations with respect to the operation of the ADF.

Infrastructure Costs

The Plan provides that the costs associated with building and implementing the capacity and environments (including, but not limited to, labor, hardware, software, installation, testing, etc., as well as associated on-going operational costs) will be borne by FINRA (except in the event of an Extraordinary Upgrade).

Should FINRA need to add capacity in order to accommodate additional capacity requests, the Plan provides that FINRA will notify the requesting ADF Trading Centers as to the maximum volumes they are permitted to submit until such time as the upgrades have been installed and tested and the ADF Trading Centers have been recertified at the requested level. Until such time that the upgrades are made, FINRA will suspend the application of all Capacity Usage Fees, as described in greater detail below.

Excess Fees

If an ADF Trading Center exceeds its Certified Peak Transaction Volume (which is equivalent to the request on the ADF Trading Center Volume Projections Form for ''Transactions per Day'' for Projected Peak Days) in one or more categories on one or more days in a given calendar month, the Plan sets forth the following Excess Fees that will apply:

Level	Percentage exceeded	1–2 days	3–5 days	6–10 days	>10 days
1	<25%	N/A	$250	$500	$750
2	25%–<50%	$250	500	750	1,000
3	50% or more	500	750	1,000	2,000

[18] In the event that all of the ADF Trading Centers have no changes or de minimis changes to their projections from a previous quarter for which they were tested and certified, the Plan provides that FINRA may forego the quarterly certification system test and certify the parties for the coming quarter. If FINRA's Product Management team is unable to conduct the certification test prior to the start of the coming quarter, the Plan provides that the ADF Trading Center(s) will be conditionally certified at the previous quarter's levels and all Capacity Usage Fees will be suspended until Product Management is able to conduct a test and officially certify the ADF Trading Center(s).

All incidents for a calendar month will be assessed at the highest level rate that any incident in that month achieved and at the highest dollar amount based on the number of days.[19] As described above, ADF Trading Centers submit separate volume projections for quote, media trade, total trade (i.e., media and non-media), and order reporting activity. These projections are broken out by NMS data plan, so the ADF Trading Center will submit separate projections in these categories for UTP Securities volume and for CTA Securities volume.[20] For purposes of calculating the Excess Fee, accruals of incidents apply separately for quote, trade and order reporting activity and for each NMS data plan to determine whether multiple incidents result in Category 1, 2, or 3 level fees.[21]

The Plan provides that, in assessing the Excess Fee, FINRA will (1) use its own metrics to determine if an ADF Trading Center has exceeded its Certified Capacity; (2) notify each ADF Trading Center as soon as possible after it has exceeded its Certified Capacity; and (3) notify each ADF Trading Center when it has incurred an Excess Fee. Any Excess Fee incurred during a month will appear on that month's invoice.

As set forth in the Plan, FINRA will not assess the Excess Fee for the first quarter during which an ADF Trading Center begins operating on the ADF. If an ADF Trading Center begins operations mid-quarter, FINRA will waive the Excess Fee only for the remainder of that quarter.

Shortfall Fees

If an ADF Trading Center does not achieve certain thresholds of both their Projected Average Transaction Volumes and their Certified Peak Transaction Volume in one or more categories on one or more days in a given calendar month, the Plan sets forth the following Shortfall Fees that will apply:

For Projected Average Transaction Volume:

Level	Percentage shortfall	1–2 days	3–5 days	6–10 days	>10 days
1	10–<15%	N/A	$125	$250	$375
2	15%–<25%	$125	250	375	500
3	25% or more	250	375	500	1000

For Certified Peak Transaction Volume:

Level	Percentage shortfall	1–2 days	3–5 days	6–10 days	>10 days
1	50–<60%	N/A	$125	$250	$375
2	60%–<75%	$125	250	375	500
3	75% or more	250	375	500	1000

All incidents for a calendar month will be assessed at the highest level rate that any incident in that month achieved and at the highest dollar amount based on the number of days.[22] As described above, ADF Trading Centers submit separate volume projections for quote, media trade, total (media and non-media) trade, and order reporting. These projections are broken out by NMS data plan, so the ADF Trading Center will submit separate projections for UTP Securities volume and for CTA Securities volume. For purposes of calculating Shortfall Fees, accruals of incidents apply separately for quote, total trade, and order reporting activity and for each NMS data plan to determine whether multiple incidents result in Category 1, 2, or 3 level fees.[23]

In assessing Shortfall Fees, FINRA will (1) use its own metrics to determine if an ADF Trading Center has fallen below the minimum threshold of activity; (2) provide weekly updates to each ADF Trading Center on their capacity usage; and (3) notify each ADF Trading Center when it has incurred a Shortfall Fee. Any Shortfall Fees incurred during a month will appear on that month's invoice.

As set forth in the Plan, FINRA will not assess the Shortfall Fee for the first quarter during which an ADF Trading Center begins operating on the ADF. If an ADF Trading Center begins operations mid-quarter, FINRA will waive the Shortfall Fee only for the remainder of that quarter.

SIP NMS Capacity Penalties

In addition to making sure that the ADF platform has sufficient infrastructure capacity to handle an ADF Trading Center's message traffic, the Plan provides that FINRA is also responsible for purchasing appropriate levels of capacity in accordance with the NMS data plans. FINRA makes the capacity purchases based on the needs

[19] For example, if in one month an ADF Trading Center has one Level 1 incident, one Level 2 incident, and one Level 3 incident in the same category, all three incidents will be treated as Level 3 incidents, and a $750 fee would apply.

In this and the following examples, each incident refers to a discrete time when the ADF Trading Center exceeded its capacity. In this example, three different incidents are treated as three days. Since one of these incidents was a Level 3 incident, the fee to be assessed would be for three days at Level 3, or $750.

[20] For purposes of calculating the Excess and Shortfall Capacity Usage Fees, the CTA and CQ Plans will both be considered for purposes of CTA Securities volume.

[21] For example, if in one month an ADF Trading Center has one Level 1 incident in UTP Securities for trade report volume, two Level 2 incidents in CTA Securities for quote volume, and three Level 3 incidents in CTA Securities for order report volume, there would be six total incidents carrying two different fees. One fee of $250 would be levied for the two Level 2 incidents in CTA Securities for quote volume. Another fee of $750 would be levied for the three Level 3 incidents in CTA Securities for order report volume. There would be no fee for the one Level 1 incident in UTP Securities for trade report volume as it is not applicable according to the fee schedule.

[22] For example, if in one month an ADF Trading Center has one Level 1 incident, one Level 2 incident, and one Level 3 incident in the same category, all three incidents will be treated as Level 3 incidents, and a $375 fee would apply.

[23] For example, if in one month an ADF Trading Center has one Level 1 incident in UTP Securities for trade report volume, two Level 2 incidents in CTA Securities for quote volume, and three Level 3 incidents in CTA Securities for order report volume, there would be six total incidents carrying two different fees. One fee of $125 would be levied for the two Level 2 incidents in CTA Securities for quote volume. Another fee of $375 would be levied for the three Level 3 incidents in CTA Securities for order report volume. There would be no fee for the one Level 1 incident in UTP Securities for trade report volume as it is not applicable according to the fee schedule. These fees would be assessed for shortfalls for both Projected Average Transaction Volume and Certified Peak Transaction Volume.

and projections of the ADF Trading Center. FINRA will pass through any penalties incurred (under the SIP plans) and allocate them according to the ADF Trading Center that exceeds its projected message traffic. Each ADF Trading Center will be invoiced for its capacity penalties once FINRA has received its invoice from the SIP(s). In assessing SIP capacity penalties, FINRA will (1) use the SIP's metrics to determine if a penalty has been incurred and will use its own metrics to allocate the penalty to the appropriate ADF Trading Centers (in the event that more than one ADF Trading Center has exceeded its projections); and (2) notify each ADF Trading Center as soon as possible after it has exceeded its projections.

As set forth in the Plan, FINRA will not assess any SIP penalties for the first quarter during which an ADF Trading Center begins operating on the ADF if it exceeds its projected message traffic during this time. If an ADF Trading Center begins operations mid-quarter, FINRA will waive any SIP capacity penalties only for the remainder of that quarter.

FINRA is proposing to codify the Excess Fees set forth in the Plan as new FINRA Rule 7581, and the Shortfall Fees as new FINRA Rule 7582. FINRA also proposes to codify the provision in the Plan providing for the pass-through of any SIP penalties as new FINRA Rule 7583.[24]

Session Terminations

To the extent that an ADF Trading Center's data usage, in the sole discretion of FINRA staff, materially exceeds the ADF Trading Center's Certified Capacity, the Plan provides that FINRA Product Management may incrementally reduce the ADF Trading Center's data port sessions to ensure that data levels stay at or below reasonable levels. Such termination may occur on an intra-day basis and will be proportionate to the extent to which the data overage threatens the ADF system's stability and/or the ability of FINRA to meet its regulatory obligations with respect to the operation of the ADF.

ADF Certification

As noted above, an ADF Trading Center also must execute and comply with a Certification, which certifies the ADF Trading Center's compliance efforts with its obligations under Regulation NMS.[25] FINRA is proposing to amend the Certification to add an additional certification item; specifically, an acknowledgement that ADF Trading Centers must comply with the terms of the Plan with respect to the total volume of messages (quotations; trade reports; order reports) and peak transmission rates (in messages per second) that it will send to the ADF.

FINRA is also making other minor changes to the Certification. Specifically, for purposes in Item 10 of requiring that an ADF Trading Center provide sufficient public notice prior to displaying quotations through the ADF, FINRA is revising the means through which an ADF Trading Center may provide the requisite information to allow for reasonable means such as ADF Trading Center press releases, the FINRA Web site, and through other FINRA-sponsored information publication channels. FINRA also proposes to clarify that the information to be provided pursuant to this Item consists of relevant connectivity and access specifications. FINRA also proposes to delete the parenthetical language in Item 11 to better clarify the scope of that provision, which addresses instances where an ADF Trading Center ceases quoting and order reporting on the same day. FINRA also proposes to delete a reference in Item 4 to ''other ADF Trading Centers'', as that reference is duplicative of the reference in that Item to ''other FINRA members,'' as ADF Trading Centers are, by definition, FINRA members. FINRA is also changing obsolete references and provisions, including replacing references to ''NASD'' with ''FINRA''; changing references from ''ADF Operations'' to ''FINRA Market Operations,'' changing a reference from TRACS to the ADF, and deleting a provision relating to ADF Trading Centers that display quotations prior to the implementation of Regulation NMS that also seek to display quotations following the implementation of Regulation NMS. FINRA also proposes to make minor grammatical and stylistic changes, including changing ''Web site'' to ''Web site'', changing ''with the respect'' to ''with respect'' in Item 13, and denoting that certain rule references are to SEC rules. Finally, FINRA also proposes to add a signature block to the bottom of the Certification.

The proposed rule change will be effective upon Commission approval.

2. Statutory Basis

FINRA believes that the proposed rule change is consistent with the provisions of Section 15A(b)(6) of the Act,[26] which requires, among other things, that FINRA rules must be designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, and, in general, to protect investors and the public interest, and Section 15A(b)(5) of the Act,[27] which requires, among other things, that FINRA rules provide for the equitable allocation of reasonable dues, fees and other charges among members and issuers and other persons using any facility or system that FINRA operates or controls, and Section 15A(b)(9) of the Act,[28] which requires that FINRA rules not impose any burden on competition that is not necessary or appropriate.

FINRA believes that the Plan, and the proposed amendment to the Certification, are consistent with the Act because they provide an objective and transparent process for administering the capacity usage of the ADF in a manner that helps ensure that FINRA is able to maintain a high level of operability for the ADF, thereby meeting its regulatory obligations, while enhancing FINRA's ability to submit accurate volume projections to the consolidated data plans.

Specifically, the Plan provides a timeframe by which ADF Trading Centers submit initial and final volume projections for the next two calendar quarters, with final volume projections tested and certified by FINRA in the event of a capacity upgrade. The Plan also provides ADF Trading Centers with the ability to increase and decrease their capacity projections for the second quarter in the event that their actual capacity usage deviates from their projected capacity usage. The Plan also sets forth fees for excess capacity usage and shortfall capacity usage, and provides that FINRA will pass through any penalties incurred under the NMS data plans, and will allocate those penalties among the ADF Trading Centers that exceed their projected message traffic. Finally, ADF Trading Centers must sign the Certification,

[24] FINRA notes that it has submitted proposed rule change SR–FINRA–2013–053, which would, among other things, re-number Rule 7540 through Rule 7570. *See* Securities Exchange Act Release No. 71147 (December 19, 2013). FINRA will amend this filing and/or SR–FINRA–2013–053, as necessary, to reflect Commission approval of either of the proposed rule changes.

[25] A copy of the Certification was previously filed with the Commission in 2006. *See* Securities Exchange Act Release No. 54277 (August 4, 2006), 71 FR 46527 (August 14, 2006) (Notice of filing of SR–NASD–2006–091). FINRA subsequently submitted a revised Certification as part of Amendment No. 3 to that filing. *See* Securities Exchange Act Release No. 54537 (September 28, 2006), 71 FR 59173 (October 6, 2006) (Order approving SR–NASD–2006–091). In 2009, FINRA filed a revised version of the Certification as part of a proposed rule change. *See* SR–FINRA–2009–069 (October 14, 2009).

[26] 15 U.S.C. 78*o*–3(b)(6).

[27] 15 U.S.C. 78*o*–3(b)(5).

[28] 15 U.S.C. 78*o*–3(b)(9).

which requires the ADF Trading Center to certify that it will comply with the requirements of the Plan. By requiring that ADF Trading Centers submit reasonable volume projections for quoting and trading on the ADF, and assessing fees for certain excess or shortfall capacity usage, FINRA believes the Plan will enhance its ability to ensure that the ADF has sufficient capacity to handle the volume of quote, order, and trade data submitted to the ADF while also avoiding the need for FINRA to expend unnecessary resources to maintain data capacity that will not be used.

The Plan also contains provisions that enable FINRA to meet its regulatory obligations to maintain a high level of operability for the ADF. For example, the Plan allows FINRA to make mid-quarter extraordinary system upgrades, and assess ADF Trading Centers for those costs accordingly, in the event that the ADF Trading Center's volume overrun threatens FINRA's ability to meet its regulatory obligations. The Plan also allows FINRA to incrementally terminate an ADF Trading Center's data port sessions in the event that the ADF Trading Center's data usage materially exceeds the ADF Trading Center's Certified Capacity, to the extent such overage threatens the ADF system's stability or the ability of FINRA to meet its regulatory obligations with respect to the operation of the ADF.

Similarly, FINRA believes that the new requirement in the Certification that an ADF Trading Center certify that it will comply with the terms of the Plan will facilitate FINRA's ability to administer the ADF in a manner consistent with its regulatory obligations. The change to the Certification relating to the manner in which an ADF Trading Center will provide public notice of certain information will increase the means through which such notice may be provided, potentially reaching more market participants. FINRA believes that the remaining changes to the Certification will result in a more current, and therefore more accurate, document.

With respect to the proposed Excess and Shortfall Fees, FINRA believes such fees provide for the equitable allocation of fees and other charges among ADF Trading Centers, and do not impose a burden on competition that it is not necessary or appropriate. FINRA notes that the methodology for calculating both the Excess and Shortfall Fees will apply equally to all ADF Trading Centers. Moreover, FINRA believes that the concept of an Excess Fee is reasonable and appropriate given the potential consequences of overrunning volume projections (e.g., the ADF is unable to process the message traffic and FINRA could incur increased costs by purchasing additional capacity to support the increased message traffic to the NMS data plans). FINRA also believes that the concept of the Shortfall Fee is reasonable and appropriate, as it provides incentives for ADF Trading Centers to furnish FINRA with meaningful capacity projections and minimizes the likelihood of FINRA ''overbuilding'' capacity in response to unreasonably high and unrealistic capacity projections.

FINRA also believes that it is reasonable and appropriate to assess the Excess and Shortfall Fees on quote, trade and order reporting activity. FINRA proposes to assess the Excess and Shortfall Fees both for quote and trade reporting activity because FINRA pays money under both the CTA/CQ and the UTP Plans for quote and trade reporting [29] and, in the case of the Excess Fee, may be assessed a penalty under the CTA/CQ Plans if it exceeds its projections for either quote or trading activity. Although FINRA does not purchase capacity from the SIPs for purposes of order reporting, FINRA does incur costs in purchasing the necessary hardware and software to supporting the intake and storage of such information.

FINRA also believes that the methodology for assessing the Excess and Shortfall Fees is consistent with the Act. Similar to the CTA Plan, FINRA will calculate the Excess Fee by evaluating whether peak message volume in the three message categories (quotes, trade reporting, and order reporting) has exceeded its Certified Peak Transaction Volume, with the amount of the Excess Fee determined by the extent and duration of the ADF Trading Center's excess usage.[30] As such, an ADF Trading Center that exceeds its Certified Peak Transaction Volume to a lesser extent or for a shorter duration than another ADF Trading Center will pay a proportionately lower Excess Fee. With respect to the Shortfall Fee, FINRA will calculate such fees by evaluating whether the ADF Trading Center's Projected Average Transaction Volumes and Certified Peak Transaction Volumes in the three message categories (quotes, trade reporting, and order reporting) have met certain thresholds.[31] As such, an ADF Trading Center that does not meet its Projected Average Transaction Volumes and Certified Peak Transaction Volumes to a lesser extent or for a shorter duration than another ADF Trading Center will pay a proportionately lower Shortfall Fee. FINRA believes this methodology for imposing such fees provides for the equitable allocation of fees and other charges among ADF Trading Centers.

FINRA also believes that the Excess Fees and Shortfall Fees are consistent with the Act because the methodology for assessing those fees will provide an element of certainty to ADF Trading Centers in calculating their potential Excess and Shortfall Fees. Excess and Capacity Fees will be charged for each message category (quotes, trade reporting, and order reporting) for both the CTA/CQ and UTP Plans. All incidents in the same category (e.g., trade reporting) will be assessed at the highest level rate that any incident in that category achieved in that month, and at the highest dollar amount based on the number of days. Accruals of incidents will apply separately for the three message categories, and for the CTA/CQ and UTP plans. As such, the maximum Excess Fee that an ADF Trading Center could be charged in any given calendar month would be $12,000 (3 categories of messages x 2 plans x $2,000 maximum day/level fee). Using the same calculation, the maximum Shortfall Fee that an ADF Trading Center could be charged in any given calendar month would be $12,000 (3 categories of messages x 2 plans x 2 Shortfall Fees x $1,000 maximum day/level fee).

FINRA also notes that it will not assess the Excess or Shortfall Fees on an

[29] *See supra* note 17.

[30] FINRA proposes a methodology for calculating Excess Fees that is similar to the methodology for assessing excess fees in the CTA Plan, with slight differences. For example, for purposes of assessing its excess usage fee, the CTA Plan measures peak messages on a one-message-per-second basis measured over five minutes, whereas FINRA proposes to measure peak messages for purposes of the Excess Fees on a daily basis. *See* Exhibit A to CTA Plan, *supra* note 10. Both Plans measure the duration of a participant's excessive usage in assessing its excess fee, but FINRA examines the percentage by which the ADF Trading Center has exceeded its projections instead of in total. *Id.*

[31] FINRA notes that an ADF Trading Center may incur a Shortfall Fee based on its Projected Average Transaction Volume if its actual volumes for quote, trade and order reporting are no less than 10%–<15% below its Projected Average Transaction Volume, while it may incur a Shortfall Fee based on its Certified Peak Transaction Volume if its actual volumes for quote, trade and order reporting are no less than 50%–<60% below its Certified Peak Transaction Volume. FINRA is adopting a lower threshold for purposes of the Shortfall Fee based on Projected Average Transaction Volume because FINRA anticipates that an ADF Trading Center's actual daily volume should be closely in line with its projected average volume. In contrast, FINRA is adopting a higher threshold for purposes of the Shortfall Fee based on Certified Peak Transaction Volume because it anticipates that an ADF Trading Center may experience a greater variance between its actual daily volume and its projected peak volume.

ADF Trading Center during its first quarter of operations on the ADF or portion thereof, and will also not assess any SIP penalties on an ADF Trading Center that exceeds its projected message traffic during this time. FINRA believes these provisions are consistent with the Act because they will provide a new ADF Trading Center with the opportunity to acquire data on its quote, order and trade reporting activity on the ADF prior to making capacity projections to which the fees and SIP penalties will apply.

B. Self-Regulatory Organization's Statement on Burden on Competition

FINRA does not believe that the proposed rule change will result in any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Act. FINRA notes that the Plan is designed to assist FINRA in meeting its regulatory obligations and maintaining the stability of the ADF while enhancing FINRA's ability to submit accurate volume projections to the consolidated data plans and minimizing the need for FINRA to expend unnecessary resources to maintain data capacity that will not be used. Given that the terms of the Plan, including the Excess and Shortfall Fees, are reasonably designed, in part, to assist FINRA in minimizing unnecessary expenditures in connection with ADF data capacity, FINRA does not believe that the Plan imposes an undue burden on competition on potential ADF Trading Centers or other FINRA members. In this regard, FINRA also notes that the proposed change would apply only to those members that choose to become ADF Trading Centers and use the ADF, and that the terms of the Plan, including the Excess and Shortfall Fees, would not apply to members that are not ADF Trading Centers. Additionally, following discussions with potential ADF Trading Centers, FINRA does not believe that the proposed rule change will impose a significant operational burden on such participants. Indeed, FINRA believes that certain aspects of the proposal, such as the methodology for assessing the Excess and Shortfall Fees, will provide ADF Trading Centers with an element of certainty in calculating the potential costs they might incur in connection with the ADF. In addition, while the Plan requires that ADF Trading Centers provide reasonable capacity estimates, it generally does not restrict ADF Trading Centers' ongoing activities if they exceed such estimates, except where the ADF system's stability or the ability of FINRA to meet its regulatory obligations with respect to the ADF are threatened.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

Written comments were neither solicited nor received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

Within 45 days of the date of publication of this notice in the **Federal Register** or within such longer period (i) as the Commission may designate up to 90 days of such date if it finds such longer period to be appropriate and publishes its reasons for so finding or (ii) as to which the self-regulatory organization consents, the Commission will:

(A) By order approve or disapprove such proposed rule change, or

(B) institute proceedings to determine whether the proposed rule change should be disapproved.

IV. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed rule change is consistent with the Act. Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/sro.shtml*); or
- Send an email to *rule-comments@sec.gov*. Please include File Number SR–FINRA–2013–054 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–FINRA–2013–054. 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 offices of FINRA. 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–FINRA–2013–054, and should be submitted on or before January 29, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[32]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–00068 Filed 1–7–14; 8:45 am]

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SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–71229; File No. SR–Topaz–2013–18]

Self-Regulatory Organizations; Topaz Exchange, LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Make Non-Controversial Changes to Its Rules

January 2, 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 December 23, 2013, the Topaz Exchange, LLC (d/b/a ISE Gemini) (the ''Exchange'' or ''Topaz'') 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 a number of non-controversial and technical changes to its rules. Examples of such

[32] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

corrections include updating Topaz rule number citations and cross references, correcting typographical errors and deleting obsolete rule text. The text of the proposed rule change is available on the Exchange's Internet Web site at *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 Exchange is proposing to make a number of non-controversial changes and technical corrections to its rules. Examples of such corrections include updating rule number citations and cross-references, correcting typographical errors, and deleting obsolete rule text. Following is a narrative description of each of the corrections:

- Topaz Rule 701 (Trading Rotations) is being amended to make a non-substantive change to correct a typographical error in paragraph (b)(2) and to remove the first sentence in paragraph (c), which states that trading in options will close 2 minutes after the primary market on which the underlying stock trades closes for trading. This reference to a 4:02 p.m. closing was imported from the International Securities Exchange (''ISE'') rule book, but should have been removed when the hours of trading on the ISE were amended,[3] but was inadvertently overlooked.
- Topaz Rule 705 (Limitation of Liability) is being amended to change a non-substantive word to update the sentence structure of paragraph (a).
- Topaz Rule 715 (Types of Orders) is being amended to add the defined terms of ''Day Order'' and ''Good-Till-Cancelled Order (GTC Order).'' The addition of these two order types qualify for non-controversial treatment as there is nothing new or novel with respect to these types of orders. Additionally, the Chicago Board Options Exchange has identical order types.[4]
- Topaz Rules 803(c) is being amended to remove underlining that does not belong. Topaz Rules 803, 810 and 811 are being amended to remove cross-references to Rule 803(c)(2) and replace them with the correct cross-references, where applicable. These cross-references were imported from the ISE rule book, which were inadvertently missed when paragraph 803(c)(2) was deleted from the ISE rules.[5]
- Topaz Rule 804(d)(3) is being deleted as this provision is obsolete and no longer applicable, but was imported from the ISE rule book and (e)(2)(ii) is being amended to delete rule text that was incorrectly imported from the ISE rule book.[6]

2. Statutory Basis

The basis under the Act for this proposed rule change is the requirement under Section 6(b)(5)[7] that an exchange have rules that are designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to remove impediments to and perfect the mechanism for a free and open market and a national market system, and, in general, to protect investors and the public interest. The Exchange believes it is appropriate to make these technical corrections to its rules so that Exchange members and investors have a clear and accurate understanding of the meaning of the Exchange's rules. By removing obsolete rule text, the Exchange is eliminating any potential for confusion about how its systems operate. By updating cross-references in its rules, the Exchange is eliminating any inaccuracies. The addition of a Day Order and a GTC Order qualifies for non-controversial treatment as there is nothing new or novel with respect to these order types. Day Orders and GTC Orders merely address the time-in-force of an order and are standard, generic orders. In addition, CBOE has both of these order types in its rules.[8] The Exchange further believes that the proposed rule change is not unfairly discriminatory because it treats all market participants equally and will not have an adverse impact on any market participant.

B. Self-Regulatory Organization's Statement on Burden on Competition

Most of the proposed rule changes are non-substantive corrections to the Exchange's rules and therefore do not implicate the competition analysis. The change proposing to adopt two new order types is non-controversial as they already exist on another exchange and merely address the time-in-force of an order, and will therefore not impact competition because these order types already exist. The proposed rule changes will serve to promote regulatory clarity and consistency, thereby reducing burdens on the marketplace and facilitating investor protection.

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

Because the foregoing proposed rule change does not significantly affect the protection of investors or the public interest, does not impose any significant burden on competition, and, by its terms, does not become operative for 30 days from the date on which it was filed, or such shorter time as the Commission may designate, it has become effective pursuant to Section 19(b)(3)(A)[9] of the Act and Rule 19b–4(f)(6)[10] thereunder. The Exchange provided the Commission with written notice of its intent to file the proposed rule change, along with a brief description and text of the proposed rule change, at least five business days prior to the date of filing the proposed rule change.

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.

[3] *See* Securities Exchange Act Release No. 53248 (February 7, 2006), 71 FR 8015 (February 15, 2006) (SR–ISE–2005–58).

[4] *See* CBOE Rule 43.2(5) and (7).

[5] *See* Securities Exchange Act Release No. 69396 (April 18, 2013), 78 FR 24273 (April 24, 2013) (SR–ISE–2013–18).

[6] *See* Securities Exchange Act Release No. 69175 (March 19, 2013), 78 FR 17988 (March 25, 2013) (SR–ISE–2013–17).

[7] 15 U.S.C. 78f(b)(5).

[8] *See* note 4.

[9] 15 U.S.C. 78s(b)(3)(A).

[10] 17 CFR 240.19b–4(f)(6).

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–Topaz–2013–18 on the subject line.

Paper Comments

- Send paper comments in triplicate to Elizabeth M. Murphy, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number *SR–Topaz–2013–18.* 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–Topaz–2013–18 and should be submitted on or before January 29, 2014.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[11]

Kevin M. O'Neill,

Deputy Secretary.

[FR Doc. 2014–00073 Filed 1–7–14; 8:45 am]

BILLING CODE 8011–01–P

[11] 17 CFR 200.30–3(a)(12).

DEPARTMENT OF TRANSPORTATION

Federal Highway Administration

Every Day Counts Initiative; Request for Information

AGENCY: Federal Highway Administration (FHWA), DOT.

ACTION: Notice.

SUMMARY: This notice is a Request for Information (RFI) and comments will be used to help FHWA identify innovative, market-ready technologies that may be considered under the Every Day Counts (EDC) initiative.

DATES: Responses to this RFI should be submitted by February 15, 2014. The FHWA will consider late-filed responses to the extent practicable.

ADDRESSES: Submit responses by electronic mail to *everydaycounts@dot.gov* or through *https://www.fbo.gov.*

FOR FURTHER INFORMATION CONTACT: For questions about the program discussed herein, contact Julie Zirlin, FHWA Office of Accelerating Innovation (202) 366–9105, *Julie.Zirlin@dot.gov.* Additional information about the EDC initiative is at *http://www.fhwa.dot.gov/everydaycounts/.*

SUPPLEMENTARY INFORMATION:

Purpose of the Notice

The FHWA requests information from all sources regarding innovations that have the potential to transform the way we do business by shortening project delivery time, enhancing the safety of our roadways, and protecting the environment. The purpose of this RFI is to obtain information from State, local, and industry partners and the public regarding proven processes or technologies that have the potential to provide efficiencies in the transportation system. This RFI is issued under the FHWA Every Day Counts Initiative.

RFI Guidelines

This is not a solicitation for proposals, applications, proposal abstracts, or quotations. The purpose of this RFI notice is to conduct market research to identify proven innovations. This RFI must not be construed as a commitment by the Government to make an award, nor does the Government intend to directly or indirectly pay for any information or responses submitted as a result of this RFI. Responses to this notice are not offers and cannot be accepted by the Government to form a binding contract or issue a grant. Information obtained as a result of this RFI may be used by the Government for program planning on a non-attribution basis. Respondents should not include any information that might be considered proprietary or confidential.

Background

The FHWA has long been a leader in innovation deployment. The FHWA Administrator Victor Mendez advocates deploying innovation to: (1) Shorten project delivery time, (2) accelerate the use of new technologies to make Government more efficient, and (3) construct highways faster, safer, and to a higher quality. To that end, in 2010, FHWA launched EDC—a broad initiative aimed at shortening project delivery and speeding the deployment of proven, underutilized technologies. The EDC initiative has had a significant impact on the transportation system.

The FHWA believes that the EDC initiative is a foundational part of making innovation a cornerstone of our business and that we can identify rapidly deployable innovations to achieve the goal of better, faster, and smarter project delivery. Society and the highway industry face an unprecedented list of challenges. The public wants greater accountability in how its money is spent. Users and industry want to find ways to make roads safer. We want to preserve the environment for future generations.

EDC 1 and EDC 2 Technologies

The EDC initiative focuses on two pillars for innovation:

- *Accelerating Technology:* Technologies and solutions to improve safety, reduce congestion, produce longer-lasting infrastructure, and keep America moving and competitive in the world market.
- *Shortening Project Delivery:* Innovative practices and methods that increase our ability to deliver timely transportation projects to the public.

The EDC initiative is designed to focus on a finite set of innovations. Teams consisting of FHWA, State, local, and industry partners and State Transportation Innovation Councils work to deploy the innovations and develop performance measures to gauge their success. The following innovations were promoted in the first two rounds of EDC:

- 3D Engineered Models for Construction
- Accelerated Bridge Construction
- Adaptive Signal Control Technology
- Alternative Technical Concepts
- Clarifying the Scope of Preliminary Design
- Construction Manager/General Contractor
- Design Build
- Enhanced Technical Assistance with ongoing Environmental Impact Statements (EISs)
- Flexibilities in Rights-of-Way (ROW)
- Flexibilities in Utility Accommodation and Relocation
- Geospatial Data Collection
- Geosynthetic Reinforced Soil-Integrated Bridge System
- High Friction Surface Treatments
- Implementing Quality Environmental Documentation
- Intelligent Compaction
- Intersection and Interchange Geometrics
- Legal Sufficiency Enhancements
- Locally Administered Federal-Aid Projects
- Planning and Environmental Linkages
- Prefabricated Bridge Elements and Systems
- Programmatic Agreements
- Safety Edge℠
- SHRP2 Traffic Incident Management Responder Training
- Use of In-Lieu Fee and Mitigation Banking
- Warm Mix Asphalt

Details of these innovations can be found at *http://www.fhwa.dot.gov/everydaycounts/.*

Invitation for Comment

The FHWA invites all sources to respond to this RFI. The FHWA seeks suggestions on innovative, market-ready technologies that meet the criteria described below and may be considered for EDC3. In addition, FHWA seeks comments on user experiences with ten specific high-value innovations that may be considered for accelerated deployment under EDC3. These innovations are described below under ''Innovations of Interest.''

Respondents should not submit unique, proprietary, or patented products. The FHWA will only review suggestions of broad categories of innovations.

Responses should provide the following information for each innovation and should not exceed 10 pages for each innovation. There is no limit to the number of innovations that may be recommended.

1. Organization name.
2. Point(s) of contact, email address, and telephone number.
3. Brief description of a proven process or innovation and how it meets the following four criteria:
   - *National Impact:* Potential to benefit the transportation system nationally.
   - *Readiness:* Whether the innovation is ready to be deployed nationally.
   - *''Game Changing'':* How the innovation is transformative in saving time, money or quality.
   - *Urgency and Scale:* Potential to shorten project delivery and positively impact the environment, safety, congestion, freight movement, construction techniques, contracting methods, project costs, maintenance, preservation, or emergency response.
4. Location and date when the innovation was successfully applied in a transportation application and a description of the quantifiable performance benefits of the innovation in those applications.
5. List of supporting specifications, guidelines, and/or procedures are available to support successful national deployment.
6. List of agencies that are the champions of this innovation.

Innovations of Interest

1. Accelerated Deployment of Traffic Incident Management Performance Measurement Data Collection Using Available Low-Cost, Web-Based Technology

While the Fiscal Year 2013 Traffic Incident Management (TIM) Self-Assessment (SA) effort reflected a positive overall jump in the national SA score, the TIM SA report pointed to a problem that has the potential to impact further advances in this national indicator and threaten individual TIM program institutionalization efforts. The scores on Performance Management—especially collection time of lane closure, time responders remain at the incident scene, and the number of secondary crashes—have declined. The TIM program professionals and associations identify the inability to establish a systematic collection of performance metrics to be a significant inhibitor to the ability to institutionalize TIM. There is a need to help jurisdictions establish an integrated, multidisciplinary and ongoing TIM Performance Management program in order to institutionalize programs and measure results.

Many TIM partners may not realize that the tools to help collect and transmit performance data exist and make the task immediate and uncomplicated. For example, smartphone technology and systems such as the Traffic and Criminal Software (TraCS), funded by DOT and maintained by the Iowa DOT, make data collection easy to capture. Mobile computing devices, like tablets and smartphones, loaded with Web-based, secure software like TraCS can also be used in the field and make data collection easy for the responder with instantaneous transmission and automated analysis.

2. Road Project Coordination To Reduce Impacts and Costs

Some States, cities, and regions recognized benefits from coordinating projects between transportation agencies, utilities, and other agencies that need to do construction in the public ROW. These benefits include cost savings, earlier identification of project impacts, greater ability to reduce and manage traffic disruptions from road work, better quality road surfaces, and reduced exposure for workers. Better coordination of projects can be a ''win-win'' for public agencies, road users, and citizens by reducing the need for additional work zones. For example:

- San Francisco, California, reduced street cuts by 27 percent by coordinating ROW projects.
- Oregon corridor-level transportation management plans ensure that at least one major north-south corridor and one major east-west corridor are left unrestricted for freight and passenger travel at all times.
- Covington, Kentucky, reduced traffic disruptions and saved nearly $18,000 over several months by coordinating planned paving with water main replacement.

Project coordination can be accomplished using different methods and scopes. Coordination may be done within a single urban area, across a corridor, for a whole State, or across a region that includes neighboring States. Using a combination of methods is the most effective way to get the best results. Coordination methods include:

- *Collaboration*—Establishing a formal organization that spearheads coordination across a geographic area and having coordination meetings to discuss the next season's projects or upcoming lane closures.
- *Policy*—Creating incentives or disincentives, such as penalties for working without a permit, higher permitting fees, and strict restoration requirements for disturbing recently repaved or reconstructed streets.
- *Technology*—Using software, such as online project mapping tools, to organize and share data entered by multiple agencies so that schedules can be coordinated.

• *Performance management*—Jointly establishing performance goals for a corridor and working together to monitor and meet them.

One key new tool that will enhance the ability to coordinate projects is the Workzone Impact and Strategy Estimator software, a product of Strategic Highway Research Program 2 (SHRP2) project R11. The tool will help reduce disruption to the transportation network by assisting agencies sequencing and phasing of road projects both during the programming of projects and later during more detailed project planning and design.

3. Traffic Signal Automated Performance Measures

Poor traffic signal performance contributes to 5–10 percent of all traffic delay on the National Highway System (NHS), which contains a fraction of the estimated 311,000 traffic signals in the U.S., valued at $82.7 billion. Best practices for traffic signal operation suggest retiming signals every 3–5 years with ongoing performance monitoring. Several surveys identify phone calls or ''complaints'' as the primary performance measure for traffic signal operations and maintenance. The 2012 Traffic Signal Report Card assigned a grade of ''F'' nationally to agency monitoring and performance measurement practices. The lack of performance measurement adversely effects safety and wastes the time and money of both operating agencies and the traveling public by reducing quality and efficiency.

Traffic Signal Automated Performance Measures allow agencies to maximize the effectiveness of signal systems and improve the management of traffic signal assets by proactively monitoring performance and making low cost modifications to the detection, communications, and control systems of intersections.

Monitoring and evaluation of traffic signal systems is critical to improving safety and efficiency. The measures that are currently available enable the effectiveness of signal progression along a given corridor to be monitored using six metrics: Delay, Speed, Approach Volumes, the Purdue Phase Termination Chart, Split Monitor, and Turning Movement Volume Counts. Other measures will be incorporated in the near future.

Adaptive Signal Control Technology (ASCT), included in EDC1, provided the ability to monitor and improve traffic signal performance. Implementing performance measurement before installing ASCT reduces the risks and improves the likelihood of successful implementation. But Traffic Signal Automated Performance Measures would be applicable to all signalized intersections, not just the most challenging locations that are difficult to operate with traditional approaches, where ASCT is typically implemented.

4. Intelligent Transportation Systems for Work Zones

Travel through and around work zones can be frustrating and hazardous to the traveling public and highway workers. Unexpected congestion can have serious consequences for road users. Delays can significantly affect freight shipments and other types of travel. Serious crashes happen at congested approaches to work zones, often resulting in catastrophic loss of life. There have been several recent catastrophic crashes involving commercial vehicles where the commercial vehicle operator did not react soon enough and rear ended stopped vehicles at the end of a queue caused by a work zone, or conversely, where passenger vehicles rear ended a stopped commercial vehicle.

Several Intelligent Transportation Systems (ITS) have been developed in the last few years to address safety and mobility issues that often occur in work zones. Systems are available to do the following: determine travel time through the work zone and advise the public of travel conditions in real time; alert vehicles to a slow moving or stopped queue of vehicles so they can be prepared to stop safely (especially beneficial for commercial motor vehicles); adjust speed limits or merging in response to current traffic conditions; and provide early detection of incidents, reducing the likelihood of secondary crashes.

Several deployments of the various systems demonstrate that they provide both safety and operational benefits. The technologies have advanced to a point where they are accurate and the results are dependable. Options are available that allow systems to be scaled to the project and to make use of permanent ITS when available.

5. E–NEPA

From EDC to the recent Presidential Memorandum *Speeding Infrastructure Development through more Efficient and Effective Permitting and Environmental Review* to the Moving Ahead for Progress in the 21st Century Act, shortening the time for the National Environmental Protection Act (NEPA) project approval has been a consistent focus of FHWA. Interagency collaboration is a critical part of this process and a necessity for timely environmental reviews and approval of surface transportation projects. By improving the ability for concurrent agency reviews during the environmental review process, issues can be more quickly and clearly raised and dealt with in real time and in a transparent manner, building trust and consensus amongst the different parties. By enabling multiple agencies to interact and collaborate on an ongoing basis, especially with agreed-upon review timeframes, the product and outcome of NEPA review processes can be improved and delivered in a shorter time period, significantly accelerating project delivery.

The e-NEPA, a real-time electronic collaboration tool, provides an online workspace and collaboration forum for EIS and environmental assessment projects. It will reduce administrative workloads required to collaborate, maintain records, and create an administrative record. In addition, e-NEPA will allow State DOTs to share documents, track comments, schedule tasks with participating agencies and perform concurrent reviews for their EIS and EA projects.

6. Strategies for Improving DOT and Railroad Coordination (SHRP2 R16)

Each year construction of hundreds of public agency highway projects cross over, under, or parallel to railroad ROWs, requiring extended coordination between these public agencies and railroads. Although most go smoothly, delays in development or construction do occur. Railroads must carefully evaluate public transportation agency projects in terms of safety, engineering, and operational impacts both during construction and for decades later. For public agencies, delays while waiting on railroad reviews and agreements can increase project costs and extend renewal needs for users.

The collection of model agreements, sample contracts, training materials, and standardized best practices developed through SHRP2 will allow public agencies and railroads to identify and circumvent sources of conflict. The tools reflect research that takes into account the perspectives, processes, budgets and funding, and acknowledged best practices of both railroads and public agencies. The report, *Strategies for Improving the Project Agreement Process Between Highway Agencies and Railroads,* outlines recommended practices and offers eight different model documents to expedite negotiations.

With railroad volumes projected to continue to grow, pressures for more project coordination activity will

continue to increase. Cementing mutual understanding and streamlining the process involved will save money and time for both railroads and public agencies. In turn, road users will see the positive results of more rapid highway renewal on facilities and budget. The model agreements also lay out standardized construction and operational needs, thereby enhancing safety for workers and reducing delays for users.

7. Electronic Project Document Management Tools (e-construction)

The administration of a project through the design and construction process requires significant communications and documentation of events. This has traditionally required writing and mailing letters through a Post Office or an internal mail system, keeping project journals, maintaining large file cabinets and file rooms, using physical signatures on paper, and taking notes at in-person meetings. With the advent of enhanced electronic project management tools, different modes of meeting, communicating, and assuring a secure version approval process, we are now accelerating the decisionmaking process. Some additional benefits noted by State DOTs using this technology are improved communications and partnering, decreased cost of printing and mailing services, opportunity to perform parallel work activities.

8. Geotechnical Solutions for Soil Improvement, Rapid Embankment Construction and Stabilization of the Pavement Working Platform (SHRP2 R02)

The Geotechnical Solutions are a Technology Catalog with detailed information on 46 geoconstruction and ground improvement techniques. In addition, the product contains a Technology Selection system to aid in identifying potential technologies for ground modification based on user-defined project conditions. The geotechnical solutions are on a Web site developed as part of the research under the SHRP2 R02 project. The scope was aimed at identifying design and construction solutions for risk elements that may be encountered in project delivery related to: (a) Construction of new embankments and roadways over unstable soils, (b) widening and expansion of existing roadways and embankments and (c) stabilization of geotechnical pavement components and of working platforms. The R02 research team is deploying the product world-wide by promoting it to subject matter experts. Deployment efforts have been targeted at experienced users of the geotechnologies. While the technologies are mature, the Web sites' technology selection system and technology catalog provide a significant resource for critically important information that assists in the design and construction of ground improvement techniques.

9. Ultra High Performance Concrete for Advanced Connection Technology for Prefabricated Bridge Elements and Systems

Ultra-High Performance Concrete (UHPC) has proven to be a technology that can facilitate simplified, effective-use prefabricated bridge elements and systems (PBES). The proliferation of PBES concepts over the past 4 years has led to recognition among owners and specifiers that robust connection systems are a key part of any successful bridge construction project. The UHPC is a steel fiber reinforced cementitious composite possessing exceptionally high mechanical strengths and durability properties. Field casting of UHPC into the interstitial spaces between prefabricate components engages a strong connection concept, freeing the owner from concerns regarding the short- and long-term performance of the connection. Research and development on this topic over the past 5 years addressed specific connection concepts that are most relevant to the highway bridge community.

10. Road Diet (Roadway Configuration)

The classic roadway reconfiguration, commonly referred to as a ''road diet,'' involves converting an undivided four-lane roadway into three lanes, made up of two through lanes and a center two-way left-turn lane. The reduction of lanes allows the roadway to be reallocated for other uses such as bike lanes, pedestrian crossing islands and parking. Road diets have multiple safety and operational benefits for drivers as well as nonmotorists. Midblock locations can benefit from road diets because they tend to experience higher travel speeds, contributing to increased injury and fatality rates. More than 80 percent of pedestrians hit by vehicles traveling at 40 mph or faster die, while less than 10 percent die when hit by a vehicle traveling 20 mph or less. When appropriately applied, road diets generated benefits to users of all modes of transportation, including bicyclists, pedestrians and motorists. The resulting benefits include reduced vehicle speeds, improved mobility and access, reduced collisions and injuries and improved livability and quality of life. When modified from four travel lanes to two travel lanes with a two-way left-turn lane, roadways experienced a 29 percent reduction in all roadway crashes. The benefits to pedestrians include reduced crossing distance and fewer midblock crossing locations, which account for more than 70 percent of pedestrian fatalities.

Road diets can be low cost if planned in conjunction with reconstruction or simple overlay projects, since a road diet mostly consists of restriping. The reduction of lanes allows the roadway to be reallocated for other uses such as bike lanes, pedestrian crossing islands, and parking. Road diets have multiple safety and operational benefits for vehicles as well as pedestrians, such as:

- Decreasing vehicle travel lanes for pedestrians to cross, therefore, reducing the multiple-threat crash for pedestrians (when one vehicle stops for a pedestrian in a travel lane on a multilane road, but the motorist in the next lane does not, resulting in a crash),
- Providing room for a pedestrian crossing island,
- Improving safety for bicyclists when bike lanes are added (such lanes also create a buffer space between pedestrians and vehicles),
- Providing the opportunity for on-street parking (also a buffer between pedestrians and vehicles),
- Reducing rear-end and side-swipe crashes, and
- Improving speed limit compliance and decreasing crash severity when crashes do occur.

Issued on: December 27, 2013.

Victor M. Mendez,

FHWA Administrator.

[FR Doc. 2014–00079 Filed 1–7–14; 8:45 am]

BILLING CODE 4910–22–P

DEPARTMENT OF TRANSPORTATION

Federal Transit Administration

[Safety Advisory 14–1]

Right-of-Way Worker Protection

AGENCY: Federal Transit Administration (FTA), Department of Transportation (DOT).

ACTION: Notice of Safety Advisory.

SUMMARY: On December 31, 2013, the Federal Transit Administration (FTA) issued Safety Advisory 14–1 to provide guidance to State Safety Oversight Agencies (SSOAs) and rail fixed guideway public transportation agencies on redundant protections for roadway workers in the rail transit industry, and review and revision of rules and procedures to protect roadway workers from trains and moving equipment. FTA

issued this guidance in response to a number of recent accidents in the industry, and two urgent recommendations by the National Transportation Safety Board (NTSB). FTA's Safety Advisory 14–1, ''Right-of-Way Worker Protection,'' is available in its entirety on the agency's public Web site (*http://www.fta.dot.gov/tso.html*). Further, FTA has asked each SSOA to coordinate with every rail transit agency within its jurisdiction to complete and submit Appendix 1 to Safety Advisory 14–1, ''Right-of-Way Worker Protection Assessment Checklist,'' and to conduct formal hazard analyses regarding the presence of workers in rail transit rights-of-way.

FOR FURTHER INFORMATION CONTACT: For program matters, Thomas Littleton, Associate Administrator for Safety and Oversight, telephone (202) 366–9239 or *Thomas.Littleton@dot.gov.* For legal matters, Scott Biehl, Senior Counsel, telephone (202) 366–0826 or *Scott.Biehl@dot.gov.*

SUPPLEMENTARY INFORMATION: On December 19, 2013, the NTSB issued two urgent safety recommendations to FTA. The first, R–13–39, recommends that all rail transit agencies be required to provide redundant protection for their roadway workers, such as positive train control, secondary warning devices, or shunting devices on track. The second, R–13–40, recommends that all rail transit agencies be required to review their rules and procedures for wayside workers and revise them, as necessary, to eliminate any authorization for worker access to transit rights-of-way in which the workers are dependent solely upon themselves to provide protection from trains and moving equipment. These two NTSB recommendations follow an October 19, 2013 accident in which two workers inspecting a dip in track on the Bay Area Rapid Transit (BART) system were killed when both their backs were turned to a train traveling more than sixty miles per hour. The workers had access to the BART right-of-way under a procedure called ''simple approval,'' which required mere notification to the agency's operations control center—there were no other protections in place for their safety.

The two recommendations are not limited to the BART accident, however. R–13–39 and R–13–40 reflect the results of recent NTSB investigations into fatalities and serious injuries to track workers on the rail transit systems in Boston, Chicago, Houston, Miami, New York, Sacramento, and Washington, DC. October 2013 was one of the deadliest months on record for the nation's rail transit workers. Three workers were killed and two were seriously injured in two separate accidents on the rail transit right-of-way (ROW). Since 2002, 28 rail transit workers have lost their lives while working to maintain the nation's rail transit infrastructure.

We at the FTA and the U.S. Department of Transportation appreciate the urgency of the NTSB's findings, and the critical safety challenge in front of us. Over the last decade, 28 workers have been killed in accidents on the rail transit right-of-way and the systems, rules and procedures put in place to protect transit workers failed each time. We agree, wholeheartedly, with the NTSB's observation that ''all rail transit systems are at risk for roadway worker fatalities and injuries.'' In response, specifically, to R–13–39 and R–13–40, FTA is issuing Safety Advisory 14–1: Right-of-Way Worker Protection, to both the agencies that own and operate rail fixed guideway systems and the SSOAs that oversee the safety of those systems. Safety Advisory 14–1 is designed to support a comprehensive review of the Right-of-Way Worker Protection (''RWP'') programs already in place at rail transit agencies. It offers options and tools to enhance those programs. The guidance identifies available resources, current industry activities to improve RWPs, and a compilation of lessons learned from right-of-way worker accidents over the last decade, all of which are framed to help rail transit agencies assess their programs within the context of the broader national experience. Safety Advisory 14–1 is available in full on the Transit Safety and Oversight Web page of the FTA public Web site at *http://www.fta.dot.gov/tso.html,* together with the Federal Transit Administrator's *Dear Colleague* letter of December 31, 2013, and a letter of that same date from the FTA Associate Administrator for Safety and Oversight addressed to the SSOAs and the chief safety officers of rail transit agencies.

Additionally, FTA has asked each SSOA, in coordination with every rail transit agency within its jurisdiction, to complete and submit Appendix 1 to Safety Advisory 14–1, the ''Right-of-Way Worker Protection Assessment Checklist,'' no later than February 28, 2014, and to oblige every rail transit agency to conduct a formal hazard analysis for the presence of workers on its rail transit right-of-way, no later than May 16, 2014. FTA will use the data and information from the assessment checklists in conducting a broader analysis for a response to NTSB recommendation R–13–39. FTA will use the results of the formal hazard analyses in developing a full response to NTSB recommendation R–13–40. FTA has asked that the formal hazard analyses address the ''simple approval'' procedure at issue in the BART accident, as appropriate, as well as emergency and scheduled access in work zones and procedures for moving crews, both under traffic and in exclusive occupancy. Also, FTA has stated its interest in how SSOAs and rail transit agencies view the benefits of ''lock outs'' and various other redundant protections, such as positive train control, secondary warning devices, and shunting devices attached to track. Please see the summaries at *http://www.ntsb.gov/doclib/recletters/2013/R-13-039-040.pdf.*

FTA's issuance of Safety Advisory 14–1 is in accordance with the Federal Transit Administrator's authority to ''investigate public transportation accidents and incidents and provide guidance to recipients regarding prevention of accidents and incidents.'' 49 U.S.C. 5329(f)(5). The requests for information and data from the SSOAs and the rail transit agencies within their jurisdiction are based on FTA's authority to request program information pertinent to rail transit safety under the State Safety Oversight rule, 49 CFR 659.39(d).

Issued in Washington, DC this 2nd day of January, 2014.

Peter Rogoff,

Federal Transit Administrator.

[FR Doc. 2014–00076 Filed 1–7–14; 8:45 am]

BILLING CODE P

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

[U.S. DOT Docket Number NHTSA–2013–0138]

Reports, Forms, and Record Keeping Requirements

AGENCY: National Highway Traffic Safety Administration (NHTSA), U.S. Department of Transportation.

ACTION: Request for public comment on extension of a currently approved collection of information.

SUMMARY: Before a Federal agency can collect certain information from the public, it must receive approval from the Office of Management and Budget (OMB). Under procedures established by the Paperwork Reduction Act of 1995, before seeking OMB approval, Federal agencies must solicit public comment on proposed collections of

information, including extensions and reinstatement of previously approved collections.

This document describes a collection of information for which NHTSA intends to seek OMB approval.

DATES: Comments must be received on or before March 10, 2014.

ADDRESSES: You may submit comments identified by DOT Docket No. NHTSA–2013–0138 by any of the following methods:

- Federal eRulemaking Portal: Go to *http://www.regulations.gov.* Follow the online instructions for submitting comments.
- Mail: Docket Management Facility: U.S. Department of Transportation, 1200 New Jersey Avenue SE., West Building Ground Floor, Room W12–140, Washington, DC 20590–0001.
- Hand Delivery or Courier: West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., between 9 a.m. and 5 p.m. ET, Monday through Friday, except Federal holidays. Telephone: 1–800–647–5527.
- Fax: 202–493–2251.

Instructions: All submissions must include the agency name and docket number for this proposed collection of information. Note that all comments received will be posted without change to *http://www.regulations.gov,* including any personal information provided. Please see the Privacy Act heading below.

Privacy Act: Anyone is able to search the electronic form of all 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 DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477–78) or you may visit *http://DocketInfo.dot.gov.*

Docket: For access to the docket to read background documents or comments received, go to *http://www.regulations.gov.* or the street address listed above. Follow the online instructions for accessing the dockets.

FOR FURTHER INFORMATION CONTACT: Alex Ansley, Recall Management Division (NVS–215), Room W46–412, NHTSA, 1200 New Jersey Ave., Washington, DC 20590. Telephone: (202) 493–0481.

SUPPLEMENTARY INFORMATION: Under the Paperwork Reduction Act of 1995, before an agency submits a proposed collection of information to OMB for approval, it must first publish a document in the **Federal Register** providing a 60-day comment period and otherwise consult with members of the public and affected agencies concerning each proposed collection of information. The OMB has promulgated regulations describing what must be included in such a document. Under OMB's regulation, *see* 5 CFR 1320.8(d), an agency must ask for public comment on the following:

(i) 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) 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) how to enhance the quality, utility, and clarity of the information to be collected; and

(iv) how 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, e.g. permitting electronic submission of responses.

In compliance with these requirements, NHTSA asks for public comments on the following collection of information:

Title: Names and Addresses of First Purchasers of Motor Vehicles.

Type of Request: Extension of a currently approved information collection.

OMB Control Number: 2127–0044.

Affected Public: Businesses or others for profit.

Abstract: Pursuant to 49 U.S.C. 30117(b), a manufacturer of a motor vehicle or tire (except a retread tire) must maintain a record of the name and address of the first purchasers of each vehicle or tire it produces and, to the extent prescribed by regulation of the Secretary, must maintain a record of the name and address of the first purchaser of replacement equipment (except a tire) that the manufacturer produces.

Vehicle manufacturers presently collect and maintain purchaser information for business reasons, such as for warranty claims processing and marketing, and experience with this statutory requirement has shown that manufacturers have retained this information in a manner sufficient to enable them to expeditiously notify vehicle purchasers in the case of a safety recall. Based on industry custom and this experience, NHTSA therefore determined that the regulation mentioned in 49 U.S.C. 30117(b) was unnecessary as to vehicle manufacturers. As an aside, the requirement for maintaining tire purchaser information are contained in 49 CFR part 574, Tire Identification and Recordkeeping, and the burden of that information collection is not part of this information collection.

Estimated annual burden: Zero. As a practical matter, vehicle manufacturers are presently collecting from their dealers and then maintaining first purchaser information for their own commercial reasons. Therefore, the statutory requirement does not impose any additional burden.

Number of respondents: We estimate that there are roughly 1,000 manufacturers of motor vehicles that collect and keep first purchaser information.

Issued on: January 2, 2014.

Jennifer T. Timian,

Chief, Recall Management Division, NHTSA.

[FR Doc. 2014–00060 Filed 1–7–14; 8:45 am]

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Part II

Environmental Protection Agency

40 CFR Parts 60, 70, 71, et al.

Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units; Proposed Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60, 70, 71, and 98

[EPA–HQ–OAR–2013–0495; FRL–9839–4]

RIN 2060–AQ91

Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: On April 13, 2012, the EPA proposed a new source performance standard for emissions of carbon dioxide for new affected fossil fuel-fired electric utility generating units. The EPA received more than 2.5 million comments on the proposed rule. After consideration of information provided in those comments, as well as consideration of continuing changes in the electricity sector, the EPA determined that revisions in its proposed approach are warranted. Thus, in a separate action, the EPA is withdrawing the April 13, 2012, proposal, and, in this action, the EPA is proposing new standards of performance for new affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines. This action proposes a separate standard of performance for fossil fuel-fired electric utility steam generating units and integrated gasification combined cycle units that burn coal, petroleum coke and other fossil fuels that is based on partial implementation of carbon capture and storage as the best system of emission reduction. This action also proposes standards for natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle technology as the best system of emission reduction. This action also includes related proposals concerning permitting fees under Clean Air Act Title V, the Greenhouse Gas Reporting Program, and the definition of the pollutant covered under the prevention of significant deterioration program.

DATES: *Comments.* Comments must be received on or before March 10, 2014. 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 January 8, 2014, a comment to the OMB is best assured of having its full effect if the OMB receives it by February 7, 2014.

Public Hearing. A public hearing will be held on January 28, 2014, at the William Jefferson Clinton Building East, Room 1153 (Map Room), 1201 Constitution Avenue NW., Washington DC 20004. The hearing will convene at 9:00 a.m. (Eastern Standard Time) and end at 8:00 p.m. (Eastern Standard Time). Please contact Pamela Garrett at (919) (541–7966) or at *garrett.pamela@epa.gov* to register to speak at the hearing. The last day to pre-register in advance to speak at the hearing will be 2 business days in advance of the public hearing. Additionally, requests to speak will be taken the day of the hearing 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 hearing 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 this hearing is 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. 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 hearing. The EPA will provide equipment for commenters to show overhead slides or make computerized slide presentations if we receive special requests in advance. Oral testimony will be limited to 5 minutes for each commenter. The EPA encourages commenters to provide the EPA with a copy of their oral testimony electronically (via email or CD) or in hard copy form. 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 hearing to run either ahead of schedule or behind schedule. Information regarding the hearing (including information as to whether or not one will be held) will be available at: *http://www2.epa.gov/carbon-pollution-standards/.*

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2013–0495, by one of the following methods:

At the Web site http://www.regulations.gov: Follow the instructions for submitting comments.

At the Web site http://www.epa.gov/oar/docket.html: Follow the instructions for submitting comments on the EPA Air and Radiation Docket Web site.

Email: Send your comments by electronic mail (email) to *a-and-r-docket@epa.gov,* Attn: Docket ID No. EPA–HQ–OAR–2013–0495.

Facsimile: Fax your comments to (202) 566–9744, Attn: Docket ID No. EPA–HQ–OAR–2013–0495.

Mail: Send your comments to the EPA Docket Center, U.S. EPA, Mail Code 2822T, 1200 Pennsylvania Ave. NW., Washington, DC 20460, Attn: Docket ID No. EPA–HQ–OAR–2013–0495. Please include a total of two copies. 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 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–2013–0495. 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–2013–0495). 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, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2013–0495. 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) through the Technology Transfer Network (TTN). Following signature, a copy of the proposed rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/.*

FOR FURTHER INFORMATION CONTACT: 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* or 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.*

SUPPLEMENTARY INFORMATION: *Comments on the April 13, 2012 proposal.* The EPA considered comments submitted in response to the original April 13, 2012, proposal in developing this new proposal. However, we are withdrawing the original proposal. If you would like comments submitted on the April 13, 2012 rulemaking to be considered in connection with this new proposal, you should submit new comments or re-submit your previous comments. Commenters who submitted comments concerning any aspect of the original proposal will need to consider the applicability of those comments to this current proposal and submit them again, if applicable, even if the comments are exactly or substantively the same as those previously submitted, to ensure consideration in the development of the final rulemaking.

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:

AB Assembly Bill
AEP American Electric Power
AEO Annual Energy Outlook
ANSI American National Standards Institute
ASME American Society of Mechanical Engineers
ASTM American Society for Testing of Materials
BACT Best Available Control Technology
BDT Best Demonstrated Technology
BSER Best System of Emission Reduction
Btu/kWh British Thermal Units per Kilowatt-hour
Btu/lb British Thermal Units per Pound
CAA Clean Air Act
CAIR Clean Air Interstate Rule
CBI Confidential Business Information
CCS Carbon Capture and Storage (or Sequestration)
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CEMS Continuous Emissions Monitoring System
CFB Circulating Fluidized Bed
CH_4 Methane
CHP Combined Heat and Power
CO_2 Carbon Dioxide
CSAPR Cross-State Air Pollution Rule
DOE Department of Energy
DOT Department of Transportation
ECMPS Emissions Collection and Monitoring Plan System
EERS Energy Efficiency Resource Standards
EGU Electric Generating Unit
EIA Energy Information Administration
EO Executive Order
EOR Enhanced Oil Recovery
EPA Environmental Protection Agency
FB Fluidized Bed
FGD Flue Gas Desulfurization
FOAK First-of-a-kind
FR **Federal Register**
GHG Greenhouse Gas
GW Gigawatts
H_2 Hydrogen Gas
HAP Hazardous Air Pollutant
HFC Hydrofluorocarbon
HRSG Heat Recovery Steam Generator
IGCC Integrated Gasification Combined Cycle
IPCC Intergovernmental Panel on Climate Change
IPM Integrated Planning Model
IRPs Integrated Resource Plans
kg/MWh Kilogram per Megawatt-hour
kJ/kg Kilojoules per Kilogram
kWh Kilowatt-hour
lb CO_2/MMBtu Pounds of CO_2 per Million British Thermal Unit
lb CO_2/MWh Pounds of CO_2 per Megawatt-hour
lb CO_2/yr Pounds of CO_2 per Year
lb/lb-mole Pounds per Pound-Mole
LCOE Levelized Cost of Electricity
MATS Mercury and Air Toxic Standards
MMBtu/hr Million British Thermal Units per Hour
MW Megawatt

MWe Megawatt Electrical
MWh Megawatt-hour
N_2O Nitrous Oxide
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NAS National Academy of Sciences
NETL National Energy Technology Laboratory
NGCC Natural Gas Combined Cycle
NOAK nth-of-a-kind
NRC National Research Council
NSPS New Source Performance Standards
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
O_2 Oxygen Gas
OMB Office of Management and Budget
PC Pulverized Coal
PFC Perfluorocarbon
PM Particulate Matter
$PM_{2.5}$ Fine Particulate Matter
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
PUC Public Utilities Commission
RCRA Resource Conservation and Recovery Act
RFA Regulatory Flexibility Act
RGGI Regional Greenhouse Gas Initiative
RIA Regulatory Impact Analysis
RPS Renewable Portfolio Standard
RTC Response to Comments
RTP Response to Petitions
SBA Small Business Administration
SCC Social Cost of Carbon
SCR Selective Catalytic Reduction
SF_6 Sulfur Hexafluoride
SIP State Implementation Plan
SNCR Selective Non-Catalytic Reduction
SO_2 Sulfur Dioxide
SSM Startup, Shutdown, and Malfunction
Tg Teragram (one trillion (10^{12}) grams)
Tpy Tons per Year
TSD Technical Support Document
TTN Technology Transfer Network
UIC Underground Injection Control
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States
USGCRP U.S. Global Change Research Program
VCS Voluntary Consensus Standard
WGS Water Gas Shift
WWW Worldwide Web

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I. General Information

A. Executive Summary

1. Purpose of the Regulatory Action

On April 13, 2012, under the authority of Clean Air Act (CAA) section 111, the EPA proposed a new source performance standard (NSPS) to limit emissions of carbon dioxide (CO_2) from new fossil fuel-fired electric utility generating units (EGUs), including, primarily, coal- and natural gas-fired units (77 FR 22392). After consideration of the information provided in more than 2.5 million comments on the proposal, as well as consideration of continuing changes in the electricity sector, the EPA is issuing a new proposal. Today's action proposes to establish separate standards for fossil fuel-fired electric steam generating units (utility boilers and Integrated Gasification Combined Cycle (IGCC) units) and for natural gas-fired stationary combustion turbines. These proposed standards reflect separate determinations of the best system of emission reduction (BSER) adequately demonstrated for utility boilers and IGCC units and for natural gas-fired stationary combustion turbines. In contrast, the April 2012 proposal relied on a single standard and a single BSER determination for all new fossil fuel-

fired units. In addition, the applicability requirements proposed today differ from the applicability requirements in the original proposal. In light of these and other differences, the EPA is issuing a document (published separately in today's **Federal Register**) that withdraws the original proposal, as well as issuing this new proposal.

2. Summary of the Major Provisions

This action proposes a standard of performance for utility boilers and IGCC units based on partial implementation of carbon capture and storage (CCS) as the BSER. The proposed emission limit for those sources is 1,100 lb CO_2/MWh.[1] This action also proposes standards of performance for natural gas-fired stationary combustion turbines based on modern, efficient natural gas combined cycle (NGCC) technology as the BSER. The proposed emission limits for those sources are 1,000 lb CO_2/MWh for larger units and 1,100 lb CO_2/MWh for smaller units. At this time, the EPA is not proposing standards of performance for modified or reconstructed sources.

3. Costs and Benefits

As explained in the Regulatory Impact Analysis (RIA) for this proposed rule, available data—including utility announcements and EIA modeling—indicate that, even in the absence of this rule, (i) existing and anticipated economic conditions mean that few, if any, solid fossil fuel-fired EGUs will be built in the foreseeable future; and (ii) electricity generators are expected to choose new generation technologies (primarily natural gas combined cycle) that would meet the proposed standards. Therefore, based on the analysis presented in Chapter 5 of the RIA, the EPA projects that this proposed rule will result in negligible CO_2 emission changes, quantified benefits, and costs by 2022.[2] These projections are in line with utility announcements and Energy Information Administration (EIA) modeling that indicate that coal units built between now and 2020 would have CCS, even in the absence of this rule. However, for a variety of reasons, some companies may consider coal units that the modeling does not anticipate. Therefore, in Chapter 5 of the RIA, we also present an analysis of the project-level costs of a new coal-fired unit with partial CCS alongside the project-level costs of a new coal-fired unit without CCS.

[1] In this rulemaking, all references to lb CO_2/MWh are on a gross output basis, unless specifically noted otherwise.

[2] Conditions in the analysis year of 2022 are represented by a model year of 2020.

B. Overview

1. Why is the EPA issuing this proposed rule?

Greenhouse gas (GHG) pollution[3] threatens the American public's health and welfare by contributing to long-lasting changes in our climate 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 drought in the West and Southwest; 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.

The U.S. Supreme Court ruled that GHGs meet the definition of ''air pollutant'' in the CAA, and this decision clarified that the CAA's authorities and requirements apply to GHG emissions. Unlike most other air pollutants, GHGs may persist in the atmosphere from decades to millennia, depending on the specific greenhouse gas. This special characteristic makes it crucial to take initial steps 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. This rule will ensure that the next generation of fossil fuel-fired power plants in this country will use modern technologies that limit harmful carbon pollution.

On April 13, 2012, the EPA issued a proposed rule to limit GHG emissions from fossil fuel-fired power plants by establishing a single standard applicable to all new fossil fuel-fired EGUs serving intermediate and base load power demand. After consideration of the information provided in more than 2.5 million comments on the proposal, as well as consideration of continuing changes in the electricity sector,[4] the EPA is issuing a new proposal to establish separate standards for fossil fuel-fired electric steam generating units (utility boilers and IGCC units) and for natural gas-fired stationary combustion turbines. These proposed standards reflect separate determinations of the BSER adequately demonstrated for utility boilers and IGCC units and for natural gas-fired stationary combustion turbines. Because, in contrast, the April 2012 proposal relied on a single standard for all new fossil fuel-fired units, the EPA is issuing, as a final action, a document (published separately in today's **Federal Register**) that withdraws the original proposal, as well as issuing this new proposal.

[3] 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).

[4] For example, since April 2012, there has been significant progress on two CCS projects (Kemper County and Boundary Dam), and they are now both over 75 percent complete. Two other projects have continued to make progress toward construction (Texas Clean Energy Project and Hydrogen Energy California Project).

2. What authority is the EPA relying on to address power plant CO_2 emissions?

Congress established requirements under section 111 of the 1970 CAA to control air pollution from new stationary sources through NSPS. Specifically, section 111 requires the EPA to set technology-based standards for new stationary sources to minimize emissions of air pollution to the environment. For more than four decades, the EPA has used its authority under section 111 to set cost-effective emission standards that ensure newly constructed sources use the best performing technologies to limit emissions of harmful air pollutants. In this proposal, the EPA is following the same well-established, customary interpretation and application of the law under section 111 to address GHG emissions from new fossil fuel-fired power plants.

3. What sources should the EPA include as it develops proposed standards for GHGs for power plants?

Before determining the appropriate technologies and levels of control that represent BSER for GHG emissions, the EPA must first identify the appropriate sources to control.

The starting point is to consider whether, given current trends concerning coal-fired and natural gas-fired power plants and the nature of GHGs, the EPA should regulate CO_2 from these power plants through the same NSPS regulatory structure that EPA has established for conventional pollutants. The EPA's NSPS regulations already regulate conventional pollutants from these sources under two 40 CFR part 60 subparts: subpart Da, electric utility steam generating units, which includes both steam electric utility boilers and IGCC units, and subpart KKKK, stationary combustion turbines, which includes both simple cycle and combined cycle stationary combustion turbines.

For sources covered under subpart Da, the original proposal relied on analyses,

primarily undertaken by EIA, indicating that, while substantial reliance on coal-fired electricity generation would continue in the future, few, if any, new coal-fired power plants were likely to be built by 2025. Based in part on these results, the EPA concluded that it was appropriate to propose in April 2012 a single fuel-neutral standard covering all intermediate and base load units based on the performance of recently constructed NGCC units. In light of developments in the electricity sector since the April 2012 proposal, and in response to numerous comments on the proposal itself, the EPA is changing the approach in today's document and proposing to set separate standards for new sources covered by subpart Da.[5]

The EPA notes that, since the original April 2012 proposal, a few coal-fired units have reached the advanced stages of construction and development, which suggests that proposing a separate standard for coal-fired units is appropriate. Since the original proposal, progress on Southern Company's Kemper County Energy Facility, an IGCC facility that will implement partial CCS, has continued, and the project is now over 75 percent complete. Similarly, SaskPower's Boundary Dam CCS Project in Estevan, Saskatchewan, a project that will fully integrate the rebuilt 110 MW coal-fired Unit #3 with available CCS technology to capture 90 percent of its CO_2 emissions, is more than 75 percent complete. Performance testing is expected to commence in late 2013 and the facility is expected to be fully operational in 2014.

Additionally, two other IGCC projects, Summit Power's Texas Clean Energy Project (TCEP) and the Hydrogen Energy California Project (HECA)—both of which are IGCC units with CCS—continue to move forward. Further, NRG Energy is developing a commercial-scale post-combustion carbon capture project at the company's W.A. Parish generating station southwest of Houston, Texas. The facility is expected to be operational in 2015. Continued progress on these projects is consistent with the EIA modeling which projects that few, if any, new coal-fired EGUs would be built in this decade and that those that are built would include CCS.[6] The existence and apparent ongoing viability of these projects which include CCS justify a separate BSER determination for new fossil fuel-fired utility boilers and IGCC power plants.

In addition to these projects, a number of commenters (on the April 2012 proposal) noted that, if natural gas prices increase, there could be greater interest in the construction of additional coal-fired generation capacity. This, too, is consistent with the EIA analysis, which also suggests that, in a limited number of potential scenarios generally associated with both significantly higher than anticipated electric demand and significantly higher than expected natural gas prices, some additional new coal-fired generation capacity may be built beyond 2020. It is also consistent with publicly available electric utility Integrated Resource Plans (IRPs).[7]

Many of those IRPs indicated the utilities' interest in developing some amount of generating capacity using other intermediate-load and base load technologies, in addition to new NGCC capacity, to meet future demand (albeit, almost always at a higher cost than NGCC technology). Only a few utilities' IRPs indicated that new coal-fired generation without CCS was a technology option that was being considered to meet future demand. Finally, a number of commenters suggested that it was important to set standards that preserve options for fuel diversity, particularly if natural gas prices exceed projected levels. Given this information, the EPA believes that it is appropriate to set a separate standard for solid fossil fuel-fired EGUs, both to address the small number of coal plants that evidence suggests might get built and to set a standard that is robust across a full range of possible futures in the energy and electricity sectors.

Utility announcements about the status of coal projects, IRPs, and EIA projections suggest that, by far, the largest sources of new fossil fuel-fired electricity generation are likely to be NGCC units. The EPA believes, therefore, that it is also appropriate to set a standard for stationary combustion turbines used as EGUs. These units are currently covered under subpart KKKK (stationary combustion turbines).

The EPA also proposes to maintain the definition of EGUs under the NSPS that differentiates between EGUs (sources used primarily for generating electricity for sale to the grid) and non-EGUs (turbines primarily used to generate steam and/or electricity for on-site use). That definition defines EGUs as units that sell more than one-third of their potential electric output to the grid. Under this definition, most simple cycle ''peaking'' stationary combustion turbines, which typically sell significantly less than one-third of their potential electric output to the grid, would not be affected by today's proposal.

Finally, the EPA is not proposing standards today for one conventional coal-fired EGU project which, based on current information, appears to be the only such project under development that has an active air permit and that has not already commenced construction for NSPS purposes. If the EPA observes that the project is truly proceeding, it may propose a new source performance standard specifically for that source at the time the EPA finalizes today's proposed rule.

4. What is the EPA's general approach to setting standards for new sources under Section 111(b)?

Section 111(b) requires the EPA to identify the ''best system of emission reduction … adequately demonstrated'' (BSER) available to limit pollution. The CAA and subsequent court decisions (detailed later in this notice) identify the factors for the EPA to consider in a BSER determination. For this rulemaking, the following factors are key: feasibility, costs, size of emission reductions and technology.

Feasibility: The EPA considers whether the system of emission reduction is technically feasible.

Costs: The EPA considers whether the costs of the system are reasonable.

Size of emission reductions: The EPA considers the amount of emissions reductions that the system would generate.

Technology: The EPA considers whether the system promotes the implementation and further development of technology.

After considering these four factors, we propose that efficient generation technology implementing partial CCS is the BSER for new affected fossil fuel-fired boilers and IGCC units (subpart Da sources) and modern, efficient NGCC technology is the BSER for new affected combustion turbines (subpart KKKK sources). The foundations for these determinations are described in Sections VII and VIII.

5. What is BSER for new fossil fuel-fired utility boilers and IGCC units?

Power generated from the combustion or gasification of coal emits more CO_2 than power generated from the combustion of natural gas or by other

[5] While the emphasis of EPA's BSER determination is on coal- and petcoke-fired units, the subpart covers all fossil fuel-fired EGU boilers and IGCC units, including those burning oil and gas.

[6] Even in its sensitivity analysis, the EIA does not project any additional coal projects beyond its reference case until 2023, in a case where power companies assume no emission limitations for GHGs, and until 2024 in any sensitivity analysis in which there are emission limitations for GHGs.

[7] IRPs are planning documents that many Public Utility Commissions require utilities to file outlining their plans to meet future demand. Many of the IRPs that the EPA has reviewed included planning horizons of ten years or more.

means, such as solar or wind. If any new coal-fired unit is built, its CO_2 emissions would be approximately double that of a new NGCC unit of comparable capacity. Thus, it is important to set a standard for any new coal plant that might be built.

The three alternatives the EPA considered in the BSER analysis for new fossil fuel-fired utility boilers and IGCC units are: (1) highly efficient new generation that does not include CCS technology, (2) highly efficient new generation with ''full capture'' CCS and (3) highly efficient new generation with ''partial capture'' CCS.

Generation technologies representing enhancements in operational efficiency (e.g., supercritical or ultra-supercritical coal-fired boilers or IGCC units) are clearly technically feasible and present little or no incremental cost compared to the types of technologies that some companies are considering for new coal-fired generation capacity. However, they do not provide meaningful reductions in CO_2 emissions from new sources. Efficiency-improvement technologies alone result in only very small reductions (several percent) in CO_2 emissions, especially in contrast to those achieved by the application of CCS. Determining that these high-efficiency generating technologies represent the BSER for CO_2 emissions from coal-fired generation would fail to promote the development and deployment of CO_2 pollution-reduction technology from power plants. In fact, a determination that this efficiency-enhancing technology alone, as opposed to CCS, is the BSER for CO_2 emissions from new coal-fired generation likely would inhibit the development of technology that could reduce CO_2 emissions significantly, thus defeating one of the purposes of the CAA's NSPS provisions. For example, during its pilot-scale CCS demonstration at the Mountaineer Plant in New Haven, WV, American Electric Power (AEP) announced in 2011 that it was placing on hold its plans to scale-up the CCS system, citing the uncertain status of U.S. climate policy as a key contributing factor to its decision.

An assessment of the technical feasibility and availability of CCS indicates that nearly all of the coal-fired power plants that are currently under development are designed to use some type of CCS. In most cases, the projects will sell or use the captured CO_2 to generate additional revenue. These projects include the following (note that each of the projects has obtained some governmental financial assistance):

Southern Company's Kemper County Energy Facility, a 582 MW IGCC power plant that is currently under construction in Kemper County, Mississippi. The plant will include a CCS system designed to capture approximately 65 percent of the produced CO_2.

SaskPower's Boundary Dam CCS Project, in Estevan, Saskatchewan, Canada, is a commercial-scale CCS project that will fully integrate the rebuilt 110 MW coal-fired Unit #3 with available CCS technology to capture 90 percent of its CO_2 emissions.

Texas Clean Energy Project (TCEP), an IGCC plant near Odessa, Texas, that is under development by the Summit Power Group, Inc. (Summit). TCEP is a 400 MW IGCC plant that expects to capture approximately 90 percent of the produced CO_2.

Hydrogen Energy California, LLC (HECA), is proposing to build a plant similar to TCEP in western Kern County, California. The HECA plant is an IGCC plant fueled by coal and petroleum coke that will produce 300 MW of power and will capture CO_2 for use in enhanced oil recovery (EOR) operations. They expect to capture approximately 90 percent of the produced CO_2.

The above examples suggest that project developers who are incorporating CCS generally considered two variants: either a partial CCS system or a full CCS system (i.e., usually 90 percent capture or greater). Therefore, the EPA considered both options.

In assessing whether the cost of a certain option is reasonable, the EPA first considered the appropriate frame of reference. Power companies often choose the lowest cost form of generation when determining what type of new generation to build. Based on both the EIA modeling and utility IRPs, there appears to be a general acceptance that the lowest cost form of new power generation is NGCC.

Many states find value in coal investments and have policies and incentives to encourage coal energy generation. Utility IRPs (as well as comments on the April 2012 proposal) suggest that many companies also find value in other factors, such as fuel diversity, and are often willing to pay a premium for it. Utility IRPs suggest that a range of technologies can meet the preference for fuel diversity from a dispatchable form of generation that can provide intermediate or base-load power, including coal without CCS, coal with CCS and nuclear. Biomass-fired power generation [8] and geothermal power generation are other technologies that are dispatchable and that could potentially meet this objective. These technologies all cost significantly more than natural gas-fired generation, which ranges from a levelized cost of electricity (LCOE) [9] of $59/MWh to $86/MWh, depending upon assumptions about natural gas prices. In assessing whether the cost of coal with CCS would have an unreasonable impact on the cost of power generation, the EPA believes it is appropriate to compare coal with CCS to this range of non-natural gas-fired electricity generation options. Based on data from the EIA and the DOE National Energy and Technology Laboratory (NETL), the EPA believes that the levelized cost of technologies other than coal with CCS and NGCC range from $80/MWh to $130/MWh. These include nuclear, from $103/MWh to $114/MWh; biomass, from $97/MWh to $130/MWh; and geothermal, from $80/MWh to $99/MWh.

The EPA believes the cost of ''full capture'' CCS without EOR is outside the range of costs that companies are considering for comparable generation and therefore should not be considered BSER for CO_2 emissions for coal-fired power plants. The EPA projects the LCOE of generation technologies with full capture CCS to be in the range of $136/MWh to $147/MWh (without EOR benefits).[10] Because these ''full capture'' CCS costs without EOR are significantly above the price range of potential alternative generation options, the EPA believes that full capture CCS does not meet the cost criterion of BSER.

Finally, the EPA considered whether implementation of ''partial capture'' CCS should be proposed to be BSER for new fossil fuel-fired utility boilers and IGCC units.

Partial capture CCS has been implemented successfully in a number of facilities over many years. The Great

[8] The proposed CO_2 emission standards would only apply to new fossil fuel-fired EGUs. New EGUs that primarily fire biomass would not be subject to these proposed standards.

[9] The levelized cost of electricity is an economic assessment of the cost of electricity from a new generating unit or plant, including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital. The LCOE value presented here are in $2007.

[10] The cost assumptions and technology configurations for these cost estimates are provided in the DOE/NETL ''Cost and Performance Baseline'' reports. For these cost estimates, we used costs for new SCPC and IGCC units utilizing bituminous coal from the reports ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'', Revision 2, Report DOE/NETL–2010/1397 (November 2010) and ''Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture'', DOE/NETL–2011/1498, May 27, 2011. Additional cost and performance information can be found in additional volumes that are available at *http://www.netl.doe.gov/energy-analyses/baseline_studies.html*.

Plains Synfuels Facility [11] is a coal gasification facility that has captured at least 50 percent of its produced CO_2 for use in EOR operations since 2000. Projects such as AEP Mountaineer have successfully demonstrated the performance of partial capture CCS on a significant portion of their exhaust stream. The Southern Company Kemper County Energy Facility will use partial CCS to capture approximately 65 percent of the produced CO_2 for use in nearby EOR operations. The facility is now more than 75 percent complete and is expecting to begin operation in 2014. The Global CCS Institute maintains a database of international CCS projects in various stages of development.[12]

The EPA analysis shows that the costs of partial CCS are comparable to costs of other non-NGCC generation. The EPA projects LCOE generation ranging from $92/MWh to $110/MWh, depending upon assumptions about technology choices and the amount, if any, of revenue from sale of CO_2 for EOR. This range compares to levelized costs in a range of $80/MWh to $130/MWh for various forms of other non-natural gas-fired electricity generation. When considered against the range of costs that would be incurred by projects deploying non-natural gas-fired electricity generation, the implementation costs of partial CCS are reasonable.

The projects in development for new coal-fired generation are few in number, and most would already meet an emission limit based on implementation of CCS.[13] As a result, a standard based on partial CCS would not have a significant impact on nationwide energy prices. Moreover, the fact that IGCC developers could meet the requirements of the standard through the use of a conventional turbine (i.e., a syngas turbine, rather than a more advanced hydrogen turbine) reinforces both the technical feasibility and cost basis of today's proposal to determine that CCS with partial capture is the BSER.

Partial CCS designed to meet an emission standard of 1,100 lb CO_2/MWh would also achieve significant emission reductions, emitting on the order of 30 to 50 percent less CO_2 than a coal-fired unit without CCS. Finally, a standard based on partial CCS clearly promotes implementation and further development of CCS technologies, and does so as much as, and perhaps even more than, a standard based on a full capture CCS requirement would.

After conducting a BSER analysis of the three options described above, the EPA proposes that new fossil fuel-fired utility boilers and IGCC units implementing partial CCS best meets the requirements for BSER. It ensures that any new fossil fuel-fired utility boiler or IGCC unit will achieve meaningful emission reductions in CO_2, and it will also encourage greater use, development, and refinement of CCS technologies. CCS technology has been adequately demonstrated, and its implementation costs are reasonable. Therefore, the EPA is basing the standards for new fossil fuel-fired utility boilers and IGCC units on partial CCS technology operating to a level of 1,100 lb CO_2/MWh.

6. What is BSER for natural gas-fired stationary combustion turbines?

We considered two alternatives in evaluating the BSER for new fossil fuel-fired stationary combustion turbines: (1) modern, efficient NGCC units and (2) modern, efficient NGCC units with CCS.

NGCC units are the most common type of new fossil fuel-fired units being planned and built today. The technology is in wide use. Nearly all new fossil fuel-fired EGUs being constructed today are using this advanced, efficient system for generating intermediate and base load power. Importantly, NGCC is an inherently lower CO_2-emitting technology. Almost every natural gas-fired stationary combined cycle unit built in the U.S. in the last five years emits approximately 50 percent less CO_2 per MWh than a typical new coal-fired plant of the same size. The design is technically feasible, and evidence shows that NGCC units are currently the lowest-cost, most efficient option for new fossil fuel-fired power generation.

By contrast, NGCC with CCS is not a configuration that is being built today. The EPA considered whether NGCC with CCS could be identified as the BSER adequately demonstrated for new stationary combustion turbines, and we decided that it could not. At this time, CCS has not been implemented for NGCC units, and we believe there is insufficient information to make a determination regarding the technical feasibility of implementing CCS at these types of units. The EPA is aware of only one NGCC unit that has implemented CCS on a portion of its exhaust stream. This contrasts with coal units where, in addition to demonstration projects, there are several full-scale projects under construction and a coal gasification plant which has been demonstrating much of the technology needed for an IGCC to capture CO_2 for more than ten years. The EPA is not aware of any demonstrations of NGCC units implementing CCS technology that would justify setting a national standard. Further, the EPA does not have sufficient information on the prospects of transferring the coal-based experience with CCS to NGCC units. In fact, CCS technology has primarily been applied to gas streams that have a relatively high to very high concentration of CO_2 (such as that from a coal combustion or coal gasification unit). The concentration of CO_2 in the flue gas stream of a coal combustion unit is normally about four times higher than the concentration of CO_2 in a natural gas-fired unit. Natural gas-fired stationary combustion turbines also operate differently from coal-fired boilers and IGCC units of similar size. The NGCC units are more easily cycled (i.e., ramped up and down as power demands increase and decrease). Adding CCS to a NGCC may limit the operating flexibility in particular during the frequent start-ups/shut-downs and the rapid load change requirements.[14] This cyclical operation, combined with the already low concentration of CO_2 in the flue gas stream, means that we cannot assume that the technology can be easily transferred to NGCC without larger scale demonstration projects on units operating more like a typical NGCC. This would be true for both partial and full capture.

After considering both technology options, the EPA is proposing to find modern, efficient NGCC technology to be the BSER for stationary combustion turbines, and we are basing the proposed standards on the performance of recently constructed NGCC units. The EPA is proposing that larger units be required to meet a standard of 1,000 lb CO_2/MWh and that smaller units (typically slightly less efficient, as noted in comments on the original proposal) be required to meet a standard of 1,100 lb CO_2/MWh.

7. How is EPA proposing to codify the requirements?

The EPA is considering two options for codifying the requirements. Under the first option EPA is proposing to codify the standards of performance for the respective sources within existing 40 CFR Part 60 subparts. Applicable

[11] While this facility is not an EGU, it has significant similarities to a coal gasification combined cycle EGU, and the implementation of the partial CCS technology would be similar enough for comparison.

[12] The Global CCS Institute, *http://www.globalccsinstitute.com/projects/browse*.

[13] For example, the Hydrogen Energy California facility plans to capture approximately 90 percent of the CO_2 in the emission stream.

[14] ''Operating Flexibility of Power Plants with CCS'', International Energy Agency (IEAGHG) report 2012/6, June 2012.

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. In the second option, the EPA is co-proposing to create a new subpart TTTT (as in the original proposal for this rulemaking) and to include all GHG standards of performance for covered sources in that newly created subpart. Unlike the original proposal, the subpart would contain two different categories, one for utility boilers and IGCC units and one for natural gas-fired stationary combustion turbines.

8. What is the organization and approach for the proposal?

This action presents the EPA's proposed approach for setting standards of performance for new affected fossil fuel-fired electric utility steam generating units (utility boilers) and stationary combustion turbines. The rationale for regulating GHG emissions from the utility power sector, including related regulatory and litigation background and relationship to other rulemakings, is presented below in Section II. The specific proposed requirements for new sources are described in detail in Section III. The rationale for reliance on a rational basis to regulate GHG emissions from fossil fuel-fired EGUs is presented in Section IV, followed by the rationale for applicability requirements in Section V. The legal requirements for establishing emission standards are discussed in detail in Section VI. Sections VII and VIII describe the rationale for each of the proposed emission standards, including an explanation of the determination of BSER for new fossil fuel-fired utility boilers and IGCC units and for natural gas-fired stationary combustion turbines, respectively. Implications for Prevention of Significant Deterioration (PSD) and title V programs are described in Section IX, and impacts of the proposed action are described in Section X. In Section XI, the agency specifically requests comments on the proposal. A discussion of statutory and executive order reviews is provided in Section XII, and the statutory authority for this action is provided in Section XIII. Also published today in the **Federal Register** is the document withdrawing the original April 13, 2012 proposal.

Today's proposal outlines an approach for setting standards of performance for emissions of carbon dioxide for new affected fossil fuel-fired electric utility steam generating units (utility boilers) and stationary combustion turbines.

C. Does this action apply to me?

The entities potentially affected by the proposed standards are shown in Table 1 below.

TABLE 1—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 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, organization, etc., 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 or 40 CFR 63.13 (General Provisions).

II. Background

In this section we discuss climate change impacts from GHG emissions, both on public health and public welfare, and the science behind the agency's conclusions. We present information about GHG emissions from fossil-fuel fired EGUs, and we describe the utility power sector and its changing structure. We then provide the statutory, regulatory, and litigation background for this proposed rule. We close this section by discussing how this proposed rule coordinates with other rulemakings and describing actions to obtain stakeholder input on this topic and the original proposed rule.

A. Climate Change Impacts From GHG Emissions

In 2009, the EPA Administrator issued the document we refer to 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 and in more detail in the RIA.

[15] "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").

1. Public Health Impacts Detailed in the 2009 Endangerment Finding

Anthropogenic emissions of GHGs and consequent climate change threaten public health in multiple aspects. By raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also leads to reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality. Climate change is expected to increase ozone pollution over broad areas of the country, including large population areas with already unhealthy surface ozone levels, and thereby increase morbidity and mortality. Other public health threats also stem from 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

Anthropogenic emissions of GHGs and consequent climate change also threaten public welfare in multiple aspects. 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. The Science Upon Which the Agency Relies

The EPA received comments in response to the April 2012 proposed NSPS rule (77 FR 22392) that addressed the scientific underpinnings of the EPA's 2009 Endangerment Finding and hence the proposed rule. The EPA carefully reviewed all of those comments. It is important to place these comments in the context of the history and associated voluminous record on this subject that has been compiled over the last few years, 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) [16]; and (3) the decision by the United States Court of Appeals for the District of Columbia Circuit (the D.C. Circuit or the Court) in 2012 to uphold the Endangerment Finding and the Reconsideration Denial.[17] [18]

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. The EPA received thousands of comments on the proposed Endangerment Finding and responded to them in depth in an 11-volume Response to Comments (RTC) document.[19] While the EPA gave careful consideration to all of the scientific and technical information received, the agency placed less weight on the much smaller number of individual studies that were not considered or reflected in the major assessments; often these studies were published after the submission deadline for those larger assessments. Primary reliance on the major scientific assessments provided the EPA greater assurance that it was basing its judgment on the best available, well-vetted science that reflected the consensus of the climate science community. The EPA reviewed individual studies not incorporated in the assessment literature largely to see if they would lead the EPA to change its interpretation of, or place less weight on, the major findings reflected in the assessment reports. From its review of individual studies submitted by commenters, the EPA concluded that these studies did not change the various conclusions and judgments the EPA drew from the more comprehensive assessment reports. The major findings of the USGCRP, IPCC, and NRC assessments supported the EPA's determination that GHGs threaten the public health and welfare of current and future generations. The EPA presented this scientific support at length in the Endangerment Finding, in its Technical Support Document (which summarized the findings of USGCRP, IPCC and NRC) [20] and in the RTC.

The EPA then reviewed ten administrative petitions for reconsideration of the Endangerment Finding in 2010. In the Reconsideration Denial, the Administrator denied those petitions on the basis that the Petitioners failed to provide substantial support for the argument that the EPA should revise the Endangerment Finding and therefore their objections were not of ''central relevance'' to the Finding. The EPA prepared an accompanying three-volume Response to Petitions (RTP) document to provide additional information, often more technical in nature, in response to the arguments, claims, and assertions by the petitioners to reconsider the Endangerment Finding.[21]

The 2009 Endangerment Finding and the 2010 Reconsideration Denial were challenged in a lawsuit before the D.C. Circuit. On June 26, 2012, the Court upheld the Endangerment Finding and the Reconsideration Denial, ruling that the Finding (including the Reconsideration Denial) was not arbitrary or capricious, was consistent with the U.S. Supreme Court's decision in *Massachusetts* v. *EPA,* which granted to the EPA the authority to regulate GHGs,[22] and was adequately supported by the administrative record.[23] The Court found that the EPA had based its decision on ''substantial scientific evidence'' and noted that the EPA's reliance on assessments was consistent with the methods decision-makers often use to make a science-based judgment.[24] The Court also agreed with the EPA that the Petitioners had ''not provided substantial support for their argument

[16] ''EPA's Denial of the Petitions to Reconsider the Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,'' 75 FR 49557 (Aug. 13, 2010) (''Reconsideration Denial'').

[17] Coalition for Responsible Regulation, Inc. v. Environmental Protection Agency (*CRR*), 684 F.3d at 102 (D.C. Cir.), reh'g en banc denied, 2012 U.S. App. LEXIS 25997, 26313 (D.C. Cir. 2012), petitions for cert. filed, No. 12–1253 (U.S. Apr. 2013).

[18] We discuss litigation history involving this rulemaking in more detail later in this section.

[19] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act: EPA's Response to Public Comments,'' *http://www.epa.gov/climatechange/endangerment/#comments* (''Response to Comments'' or ''RTC'').

[20] ''Technical Support Document for Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(s) of the Clean Air Act (Dec. 7, 2009), *http://www.epa.gov/climatechange/Downloads/endangerment/Endangerment_TSD.pdf* (TSD).

[21] *http://www.epa.gov/climatechange/endangerment/petitions.html.*

[22] 549 U.S. 497 (2007).

[23] *CRR,* 684 F.3d at 117–27.

[24] *Id.* at 121.

that the Endangerment Finding should be revised.'' [25] Moreover, the Court supported the EPA's reliance on the major scientific assessment reports conducted by USGCRP, IPCC, and NRC and found that:

> The EPA evaluated the processes used to develop the various assessment reports, reviewed their contents, and considered the depth of the scientific consensus the reports represented. Based on these evaluations, the EPA determined the assessments represented the best source material to use in deciding whether GHG emissions may be reasonably anticipated to endanger public health or welfare.[26]

As the Court stated—

> It makes no difference that much of the scientific evidence in large part consisted of 'syntheses' of individual studies and research. Even individual studies and research papers often synthesize past work in an area and then build upon it. This is how science works. The EPA is not required to re-prove the existence of the atom every time it approaches a scientific question.[27]

In the context of this extensive record and the recent affirmation of the Endangerment Finding by the Court, the EPA considered all of the submitted comments and reports for the April 2012 proposed NSPS rule. As it did in the Endangerment Finding, the EPA gave careful consideration to all of the scientific and technical comments and information in the record. The major peer-reviewed scientific assessments, however, continue to be the primary scientific and technical basis for the Administrator's judgment regarding the threats to public health and welfare posed by GHGs.

Commenters submitted two major peer-reviewed scientific assessments released after the administrative record concerning the Endangerment Finding closed following the EPA's 2010 Reconsideration Denial: the IPCC's 2012 ''Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation'' (SREX) and the NRC's 2011 ''Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia'' (Climate Stabilization Targets).

According to the IPCC in the SREX, ''A changing climate leads to changes in the frequency, intensity, spatial extent, duration, and timing of extreme weather and climate events, and can result in unprecedented extreme weather and climate events.[28]'' The SREX documents observational evidence of changes in some weather and climate extremes that have occurred globally since 1950. The assessment also provides evidence regarding the cause of some of these changes to elevated concentrations of GHGs, including warming of extreme daily temperatures, intensified extreme precipitation events, and increases in extreme coastal high water levels due to rising sea level. The SREX projects further increases in some extreme weather and climate events during the 21st century. Combined with increasing vulnerability and exposure of populations and assets, changes in extreme weather and climate events have consequences for disaster risk, with particular impacts on the water, agriculture and food security and health sectors.

In the Climate Stabilization Targets assessment, the NRC states:

> 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.[29]

The assessment concludes that carbon dioxide emissions will alter the atmosphere's composition and therefore the climate for thousands of years; and attempts to quantify the results of stabilizing GHG concentrations at different levels. The report also projects the occurrence of several specific climate change impacts, finding warming could lead to increases in heavy rainfall and decreases in crop yields and Arctic sea ice extent, along with other significant changes in precipitation and stream flow. For an increase in global average temperature of 1 to 2 °C above pre-industrial levels, the assessment found that the area burnt by wildfires in western North America will likely more than double and coral bleaching and erosion will increase due both to warming and ocean acidification. An increase of 3 °C will lead to a sea level rise of 0.5 to 1 meter by 2100. With an increase of 4 °C, the average summer in the United States would be as warm as the warmest summers of the past century. The assessment notes that although many important aspects of climate change are difficult to quantify, the risk of adverse impacts is likely to increase with increasing temperature, and the risk of surprises can be expected to increase with the duration and magnitude of the warming.

Several other National Academy assessments regarding climate have also been released recently. The EPA has reviewed these assessments and finds that in general, the improved understanding of the climate system they and the two assessments described above present strengthens the case that GHGs are endangering public health and welfare. Three of the new NRC assessments provide estimates of projected global sea level rise that are larger than, and in some cases more than twice as large as, the rise estimated in a 2007 IPCC assessment of between 0.18 and 0.59 meters by the end of the century, relative to 1990. (It should be noted that in 2007, the IPCC stated that including poorly understood ice sheet processes could lead to an increase in the projections.) [30] While these three NRC assessments continue to recognize and characterize the uncertainty inherent in accounting for ice sheet processes, these revised estimates strongly support and strengthen the existing finding that GHGs are reasonably anticipated to endanger public health and welfare. Other key findings of the recent assessments are described briefly below:

One of these assessments projects a global sea level rise of 0.5 to 1.4 meters by 2100, which is sufficient to lead to rising relative sea level even in the northern states.[31] Another assessment considers potential impacts of sea level rise and suggests that ''the Department of the Navy should expect roughly 0.4 to 2 meters global average sea-level rise by 2100.[32] This assessment also recommends preparing for increased needs for humanitarian aid; responding to the effects of climate change in geopolitical hotspots, including possible mass migrations; and addressing changing security needs in the Arctic as sea ice retreats. A third NRC assessment found that it would be ''prudent for security analysts to expect climate surprises in the coming decade . . . and for them to become progressively more serious and more frequent thereafter[.]'' [33]

Another NRC assessment finds 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

[25] *Id.* at 125.

[26] *Id.* at 120.

[27] *Id.* at 120.

[28] SREX, p. 7.

[29] Climate Stabilization Targets, p. 3.

[30] Climate Stabilization Targets; ''National Security Implications for U.S. Naval Forces'' (2011) (National Security Implications); ''Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future'' (2012) (Sea Level Rise).

[31] Sea Level Rise, p. 4.

[32] National Security Implications, p. 9.

[33] ''Climate and Social Stress: Implications for Security Analysis'' (2012), p.3.

Earth history.'' [34] This assessment finds that CO_2 concentrations by the end of the century, without a reduction in emissions, are projected to increase to levels that Earth has not experienced for more than 30 million years.[35] The report draws potential parallels with non-linear events such as the Paleo-Eocene Thermal Maximum, a rapid global warming event about 55 million years ago associated with mass extinctions and other disruptions. The assessment notes that acidification and warming caused by GHG increases similar to the changes expected over the next hundred years likely caused up to four of the five major coral reef crises of the past 500 million years.

Similarly, another NRC assessment finds that ''[t]he chemistry of the ocean is changing at an unprecedented rate and magnitude due to anthropogenic carbon dioxide emissions; the rate of change exceeds any known to have occurred for at least the past hundreds of thousands of years.'' [36] The assessment notes that the full range of consequences is still unknown, but the risks ''threaten coral reefs, fisheries, protected species, and other natural resources of value to society.'' [37]

Comments were submitted in support of the Endangerment Finding, which provided additional documentation showing that climate change is a threat to public health and welfare. Commenters provided several individual studies and documentation of observed or projected climate changes of local importance or concern to commenters. The EPA appreciates these comments, but as previously stated, we place lesser weight on individual studies than on major scientific assessments. Local observed changes must be assessed in the context of the broader scientific picture, as it is more difficult to draw robust conclusions regarding climate change over short time scales and in small geographic regions.

The EPA plans to continue relying on the major assessments by the USGCRP, the IPCC, and the NRC. Studies from these bodies address the scientific issues that the Administrator must examine, represent the current state of knowledge on the key elements for the endangerment analysis, comprehensively cover and synthesize thousands of individual studies to obtain the majority conclusions from the body of scientific literature and undergo a rigorous and exacting standard of review by the peer expert community and U.S. government.

Several commenters argued that the Endangerment Finding should be reconsidered or overturned based on those commenters' reviews of specific climate science literature, including publications that have appeared since the EPA's 2010 Reconsideration Denial. Some commenters presented their own compilations of individual studies and other documents to support their assertions that climate change will have beneficial effects in many cases and that climate impacts will not be as severe or adverse as the EPA, and the assessment reports upon which the EPA relied, have stated. Some commenters also concluded that U.S. society will easily adapt to climate change and that it therefore does not threaten public health and welfare, and some commenters questioned the Endangerment Finding based on a 2011 EPA Inspector General's report.

The EPA reviewed the submitted information and found that overall, the commenters' critiques of the rule's scientific basis were addressed in the EPA's response to comments for the 2009 Endangerment Finding, the EPA's responses in the 2010 Reconsideration Denial, or the D.C. Circuit's 2012 decision upholding the EPA's 2009 Endangerment Finding. The EPA nonetheless carefully reviewed these comments and associated documents and found that nothing in them would change the conclusions reached in the Endangerment Finding. These recent publications submitted by commenters, and any new issues they may present, do not undermine either the significant body of scientific evidence that has accumulated over the years or the conclusions presented in the substantial peer-reviewed assessments of the USGCRP, NRC, and IPCC.

One commenter submitted emails between climate change researchers from the period 1999 to 2009 that were surreptitiously obtained from a University of East Anglia server in 2009 and publicly released in 2011. According to the commenter, these emails showed that the climatologists distorted their research results to prove that climate change causes adverse effects. The EPA reviewed these emails and found that they raised no issues that Petitioners had not already raised concerning other emails from the same incident, released in 2009. The commenter's unsubstantiated assumptions and subjective assertions regarding what the emails purport to show about the state of climate change science is not adequate evidence to challenge the voluminous and well-documented body of science that underpins the Administrator's Endangerment Finding.

Some commenters argued for reconsideration based on uncertainty regarding climate science. However, the EPA made the decision to find endangerment with full and explicit recognition of the uncertainty involved, stating that ''[t]he Administrator acknowledges that some aspects of climate change science and the projected impacts are more certain than others.'' [38] The D.C. Circuit subsequently noted that ''the existence of some uncertainty does not, without more, warrant invalidation of an endangerment finding.'' [39]

Some commenters also argued that the U.S. will adapt to climate change impacts and that therefore climate change impacts pose no threat. However, the D.C. Circuit, in *CRR,* held that considerations of adaption are irrelevant to the Endangerment determination. The Court stated, ''These contentions are foreclosed by the language of the statute and the Supreme Court's decision in *Massachusetts* v. *EPA*'' because ''predicting society's adaptive response to the dangers or harms caused by climate change'' does not inform the ''scientific judgment'' that the EPA is required to make regarding an Endangerment Finding.[40]

Some commenters raised issues regarding the EPA Inspector General's report, *Procedural Review of EPA's Greenhouse Gases Endangerment Finding Data Quality Processes.*[41] These commenters mischaracterized the report's scope and conclusions and thus overstated the significance of the Inspector General's procedural recommendations. Nothing in the Inspector General's report questions the scientific validity of the Endangerment Finding, because that report did not evaluate the scientific basis of the Endangerment Finding. Rather, the Inspector General offers recommendations for clarifying and standardizing internal procedures for documenting data quality and peer

[34] ''Understanding Earth's Deep Past: Lessons for Our Climate Future'' (2011), p.138.

[35] Ibid, p. 1.

[36] ''Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean'' (2010), p. 5.

[37] *Id.*

[38] 74 FR 66524.

[39] *CRR,* 684 F.3d at 121.

[40] *Id.* at 117. The EPA took a similar position in the Endangerment Finding, in which we responded to similar comments regarding society's ability to adapt to climate change by stating: ''Risk reduction through adaptation and GHG mitigation measures is of course a strong focal area of scientists and policy makers, including the EPA; however, the EPA considers adaptation and mitigation to be potential responses to endangerment, and as such has determined that they are outside the scope of the endangerment analysis.'' 74 FR 66512.

[41] Report No. 11–P–0702 (September 26, 2011).

review processes when referencing existing peer reviewed science in the EPA actions.[42]

In addition, some commenters argued that the Endangerment Finding should be overturned because of the carbon dioxide fertilization effect, that is, the proposition that increased amounts of carbon dioxide can spur growth of vegetation. However, these commenters did not show how the science they provide on the subject differs from the carbon dioxide fertilization science already considered by the Administrator in the Endangerment Finding or how the existence of some benefits from the carbon dioxide fertilization effect could outweigh the numerous negative impacts of climate change.

In sum, the EPA reviewed all of the comments purporting to refute the Endangerment Finding to determine whether they provide evidence that the Administrator's judgment that climate change endangers public health and welfare was flawed, because the Administrator misinterpreted the underlying assessments, because the science in new peer reviewed assessments differs from that in previous assessments, or because new individual studies provide compelling reasons for the EPA to change its interpretation of, or place less weight on, the major findings reflected in the assessment reports. In all cases, the commenters failed to demonstrate that the science that the Administrator relied on was inaccurate or that the additional information from the commenter is of central relevance to the Administrator's judgment regarding endangerment. For these reasons, the commenters on the original proposal that criticized the Endangerment Finding have not provided a sufficient basis to cast doubt on the Finding.

B. GHG Emissions From Fossil Fuel-Fired EGUs

Fossil fuel-fired electric utility generating units 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[43] (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 2 below, which presents total U.S. anthropogenic emissions and sinks of GHGs, including CO_2 emissions, for the years 1990, 2005 and 2011.[44]

TABLE 2—U.S. GHG EMISSIONS AND SINKS BY SECTOR (TERAGRAM CARBON DIOXIDE EQUIVALENT (TG CO_2 EQ.))[45]

Sector	1990	2005	2011
Energy	5,267.3	6,251.6	5,745.7
Industrial Processes	316.1	330.8	326.5
Solvent and Other Product Use	4.4	4.4	4.4
Agriculture	413.9	446.2	461.5
Land Use, Land-Use Change and Forestry	13.7	25.4	36.6
Waste	167.8	136.9	127.7
Total Emissions	6,183.3	7,195.3	6,702.3
Land Use, Land-Use Change and Forestry (Sinks)	(794.5)	(997.8)	(905.0)
Net Emissions (Sources and Sinks)	5,388.7	6,197.4	5,797.3

Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total U.S. GHG emissions, representing 78.7 percent of total 2011 GHG emissions. In 2011, fossil fuel combustion by the electric power sector—entities that burn fossil fuel and whose primary business is the generation of electricity—accounted for 39.6 percent of all energy-related CO_2 emissions. Table 3 below presents total CO_2 emissions from fossil fuel-fired EGUs, for years 1990, 2005 and 2011.[46]

TABLE 3—U.S. GHG EMISSIONS FROM GENERATION OF ELECTRICITY FROM COMBUSTION OF FOSSIL FUELS (TG CO_2 EQ.)

GHG Emissions	1990	2005	2011
Total CO_2 from fossil fuel combustion EGUs	1,820.8	2,402.1	2,158.5
—from coal	1,547.6	1,983.8	1,722.7
—from natural gas	175.3	318.8	408.8
—from petroleum	97.5	99.2	26.6

[42] Unrelated to the Endangerment Finding and its validation by the Court, the EPA has made progress towards implementing the recommendations from the Inspector General.

[43] ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2011'', Report EPA 430–R–13–001, United States Environmental Protection Agency, April 15, 2013.

[44] Sinks are a physical unit or process that stores GHGs, such as forests or underground or deep sea reservoirs of carbon dioxide.

[45] From Table 2–3 of ''Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2011'', April 15, 2013, EPA 430–R–13–001.

[46] Note that for the purposes of reporting national GHG emissions under the UNFCCC, the U.S. GHG Inventory is calculated using internationally accepted methodological guidance from the Intergovernmental Panel on Climate Change (IPCC). In accordance with IPCC guidance, CO_2 emissions from combustion of biogenic feedstocks are not reported in the energy sector, but are instead reported separately as a ''Memo item'' in the U.S. GHG Inventory. Consistent with the IPCC guidance, any carbon stock changes related to the use of biogenic feedstocks in the energy sector, and the CO_2 emissions associated with those carbon stock changes, are accounted for under the forestry and/or agricultural sectors of the U.S. GHG Inventory. Attribution of CO_2 emissions from the combustion of biogenic feedstocks by stationary sources in the energy sector to the forestry and/or agricultural sectors, in the context of U.S. GHG emissions reporting to the UNFCCC, should not be interpreted as an indication that such emissions are ''carbon neutral.''

We are aware that nitrous oxide (N_2O) and, to a lesser extent, methane (CH_4) may be emitted from fossil fuel-fired EGUs, especially from coal-fired circulating fluidized bed (CFB) combustors and from units with selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) systems installed for NO_X control. The estimated emissions for N_2O and CH_4 from fossil fuel-fired EGUs are about 17.9 and 0.4 Tg of CO_2 equivalent in 2011, respectively, which is about 0.8 percent of total CO_2 equivalent emissions from fossil fuel-fired electric power generating units. However, we are not proposing separate N_2O or CH_4 emission limits or an equivalent CO_2 emission limit in today's document because we lack more precise data on the quantity of these emissions and information on cost-effective controls. We request comment on this approach and we solicit information about the quantity of N_2O and CH_4 emissions from these affected sources and possible controls.

C. The Utility Power Sector and How Its Structure Is Changing

1. Utility Power Sector

The majority of power in the U.S. is generated from the combustion of coal, natural gas and other fossil fuels.

Natural gas-fired EGUs typically use one of two technologies: NGCC and 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) which generates steam which is used to generate power using a steam turbine (the steam cycle). The combining of these generation cycles increases the overall efficiency of the system.

Simple cycle combustion turbines only 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 fluidized bed 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 to form a syngas composed of carbon monoxide (CO) and hydrogen (H_2), which can be combusted in a combined cycle system to generate power.

2. Changing Structure of the Power Sector

a. Technological Developments and Costs

Since the April 2012 proposal, a few coal-fired units have reached the advanced stages of construction and development, which suggests that setting a separate standard for new fossil fuel-fired boilers and IGCC units is appropriate. Progress on Southern Company's Kemper County Energy Facility, which will deploy IGCC with partial CCS, has continued, and the project is now over 75 percent complete. Additionally, two other projects, Summit Power's Texas Clean Energy Project (TCEP) and the Hydrogen Energy California Project (HECA)—both of which will deploy IGCC with CCS—continue to move forward. The EIA modeling projects that coal-fired power generation will remain the single largest portion of the electricity sector beyond 2030. The EIA modeling also projects that few, if any, new coal-fired EGUs would be built in this decade and that those that are built would have CCS.[47] Continued progress on these projects is consistent with the EIA modeling that suggests that a small number of coal-fired power plants may be constructed. The primary reasons for this rate of current and projected future development of new coal projects include highly competitive natural gas prices, lower electricity demand, and increases in the supply of renewable energy.

Natural gas prices have decreased dramatically and generally stabilized in recent years, as new drilling techniques have brought additional supply to the marketplace and greatly increased the domestic resource base. As a result, natural gas prices are expected to be competitive for the foreseeable future and EIA modeling and utility announcements confirm that utilities are likely to rely heavily on natural gas to meet new demand for electricity generation. On average, as discussed below, the cost of generation from a new natural-gas fired power plant (a NGCC unit) is expected to be significantly lower than the cost of generation from a new coal-fired power plant.[48]

Other drivers that may influence decisions to build new power plants are increases in renewable energy supplies, often due to state and federal energy policies. Many states have adopted renewable portfolio standards (RPS), which require a certain portion of electricity to come from renewable energy sources such as solar or wind. The federal government has also adopted incentives for electric generation from renewable energy sources and loan guarantees for new nuclear power plants.

Due to these factors, the EIA projections from the last several years show that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity through 2020, along with renewable energy, nuclear power, and a limited amount of coal with CCS.[49]

b. Energy Sector Modeling

Various energy sector modeling efforts, including projections from the EIA and the EPA, forecast trends in new power plant construction and utilization of existing power plants that are consistent with the above-described technological developments and costs. The EIA forecasts the structure and developments in the power sector in its annual report, the Annual Energy Outlook (AEO). These reports are based on economic modeling that reflects existing policy and regulations, such as state RPS programs and federal tax credits for renewables.[50] The current report, AEO 2013,[51] (i) shows that a modest amount of coal-fired power plants that are currently under construction are expected to begin operation in the next several years (referred to as ''planned''); and (ii) projects in the reference case,[52] that a very small amount of new (''unplanned'') conventional coal-fired capacity, with CCS, will come online after 2012, and through 2034 in response to Federal and State incentives. According to the AEO 2013,

[47] Even in its sensitivity analysis that assumes higher natural gas prices and electricity demand, EIA does not project any additional coal beyond its reference case until 2023, in a case where power companies assume no GHGs emission limitations, and until 2024 in a case where power companies do assume GHGs emission limitations.

[48] Levelized Cost of New Generation Resources in the Annual Energy Outlook 2011 *http://www.eia.gov/forecasts/aeo/electricity_generation.html.*

[49] *http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf; http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf; http://prod-http-80-800498448.us-east-1.elb.amazonaws.com/w/images/6/6d/0383%282011%29.pdf.*

[50] *http://www.eia.gov/forecasts/aeo/chapter_legs_regs.cfm.*

[51] Energy Information Adminstration's Annual Energy Outlook for 2013, Final Release available at *http://www.eia.gov/forecasts/aeo/index.cfm.*

[52] EIA's reference case projections are the result of its baseline assumptions for economic growth, fuel supply, technology, and other key inputs.

the vast majority of new generating capacity during this period will be either natural gas-fired or renewable. Similarly, the EIA projections from the last several years show that natural gas is likely to be the most widely-used fossil fuel for new construction of electric generating capacity through 2020.[53]

Specifically, the AEO 2013 projects the need for 25.9 GW of additional base load or intermediate load generation capacity through 2020 (this includes projects that are under development—i.e., being constructed or in advance planning—and model-projected nuclear, coal, and NGCC projects). The vast majority of this new electric capacity (22.5 GW) is already under development (under construction or in advanced planning); it includes about 6.1 GW of new coal-fired capacity, 5.5 GW of new nuclear capacity, and 10.9 GW of new NGCC capacity. The EPA believes that most current fossil fuel-fired projects are already designed to meet limits consistent with today's proposal (or they have already commenced construction and are thus not impacted by today's notice). The AEO 2013 also projects an additional 3.4 GW of new base load capacity additions, which are model-projected (unplanned). This consists of 3.1 GW of new NGCC capacity, and 0.3 GW of new coal equipped with CCS (incentivized with some government funding). Therefore, the AEO 2013 projection suggests that this proposal would only impact small amounts of new power generating capacity through 2020, all of which is expected to already meet the proposed emissions standards without incurring further control costs. In AEO 2013, this is also true during the period from 2020 through 2034, where new model-projected (unplanned) intermediate and base load capacity is expected to be compliant with the proposed standard without incurring further control costs (i.e., an additional 45.1 GW of NGCC and no additional coal, for a total, from 2013 through 2030, of 48.2 GW of NGCC and 0.3 GW of coal with CCS).

It should be noted that under the EIA projections, existing coal-fired generation will remain an important part of the mix for power generation. Modeling from both the EIA and the EPA predict that coal-fired generation will remain the largest single source of electricity in the U.S. through 2040. Specifically, in the EIA's AEO 2013, coal will supply approximately 40 percent of all electricity in both 2020 and 2025.

The EPA modeling using the Integrated Planning Model (IPM), a detailed power sector model that the EPA uses to support power sector regulations, also shows limited future construction of new coal-fired power plants under the base case.[54] The EPA's projections from IPM can be found in the RIA.

c. Integrated Resource Plans

The trends in the power sector described above are also apparent in publicly available long-term resource plans, known as IRPs.

The EPA has reviewed publicly available IRPs from a range of companies (e.g., varying in size, location, current fuel mix), and these plans are generally consistent with both EIA and EPA modeling projections. Companies seem focused on demand-side management programs to lower future electricity demand and mostly reliant on a mix of new natural gas-fired generation and renewable energy to meet increased load demand and to replace retired generation capacity.

Notwithstanding this clear trend towards natural gas-fired generation and renewables, many of the IRPs raise fuel diversity concerns and include options to diversify new generation capacity beyond natural gas and renewable energy. Several IRPs indicate that companies are considering new nuclear generation, including either traditional nuclear power plants or small modular reactors, and new coal-fired generation capacity with and without CCS technology. Based on these IRPs, the EPA acknowledges that a small number of new coal-fired power plants may be built in the near future. While this is contrary to the economic modeling predictions, the Agency understands that economic modeling may not fully reflect the range of factors that a particular company may consider when evaluating new generation options, such as fuel diversification. By the same token, as discussed below, it is possible that some of this potential new coal-fired construction may occur because developers are able to design projects that can provide competitively priced electricity for a specific geographic region.

D. Statutory Background

Section 111 of the Clean Air Act sets forth the standards of performance for new sources (NSPS) program, and with this program, establishes mechanisms for regulating emissions of air pollutants from stationary sources that are key in this rulemaking.[55] 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.''

Once the EPA has listed a source category, the EPA proposes and then promulgates ''standards of performance'' for ''new sources'' in the category.[56] A ''new source'' is ''any stationary source, the construction or modification of which is commenced after,'' in general, the date of the proposal.[57] 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.''[58] The EPA, through regulations, has determined that certain types of changes are exempt from consideration as a modification.[59] The EPA's regulations also provide that an existing facility is also considered a new source if it undertakes a ''reconstruction,'' which is the replacement of components to such an extent that the capital costs of the new equipment or components exceed 50 percent of what is believed to be the cost of a completely new facility.[60] In establishing standards of performance, the EPA has significant discretion to create subcategories based on source type, class or size.[61]

Clean Air Act 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 controls that constitute ''the best system of emission reduction . . . adequately demonstrated'' (BSER).[62]

[53] Annual Energy Outlook 2010, 2011, 2012, and 2013.

[54] *http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation.*

[55] CAA section 111(b)(1)(A). The EPA has regulated more than 60 stationary source categories under CAA section 111. *See generally* 40 CFR subparts D–MMMM.

[56] CAA section 111(b)(1)(B).

[57] CAA section 111(a)(2).

[58] CAA section 111(a)(4).

[59] 40 CFR 60.2, 60.14(e).

[60] 40 CFR 60.15.

[61] CAA section 111(b)(2).

[62] As noted, we generally refer to this system of control as the best system of emission reduction, or

Continued

The standard that the EPA develops, based on the BSER, is commonly a numerical emissions 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 can select any measure or combination of measures that will achieve the emissions level of the standard.

Regarding other titles in the CAA, this rulemaking has implications for EGUs and other stationary sources in the CAA PSD program under Title I, part C, and the operating permits program under Title V. We discuss these implications in section IX of this preamble.

E. Regulatory and Litigation Background

The EPA initially included fossil fuel-fired EGUs (which includes EGUs that burn fossil fuel including coal, gas, oil and petroleum coke and that use different technologies, including boilers and combustion turbines) in a category that it listed under section 111(b)(1)(A), and the EPA promulgated the first set of standards of performance for EGUs in 1971, codified in subpart D.[63] As discussed in Section IV.D. of this preamble, the EPA has revised those regulations, and in some instances, revised the subparts, several times over the ensuing decades. None of these rulemakings or codifications, however, have constituted a new listing under CAA section 111(b)(1)(A).

In 1979, the EPA revised subpart D of 40 CFR part 60; as part of this revision, the EPA formed subpart Da and promulgated NSPS for electric utility steam generating units.[64] These NSPS on June 11, 1979 apply to units capable of firing more than 73 megawatts (MW) (250 MMBtu/h) heat input of fossil fuel that commenced construction, reconstruction, or modification after September 18, 1978. The NSPS for EGUs also apply to industrial-commercial-institutional cogeneration units that sell more than 25 MW and more than one-third of their potential output capacity to any utility power distribution system.

The EPA promulgated amendments to subpart Da in 2006, resulting in new criteria pollutant limitations for EGUs (the 2006 Final Rule).[65] The 2006 Final Rule did not establish standards of performance for GHG emissions. Two groups of petitioners—13 governmental entities and three environmental groups—filed petitions for judicial review of this rule by the D.C. Circuit.[66] These petitioners contended, among other issues, that the rule was required to include standards of performance for GHG emissions from EGUs.

The Court severed portions of the petitions for review of the 2006 Final Rule that related to GHG emissions. Following the U.S. Supreme Court's 2007 decision in *Massachusetts* v. *EPA,* which gave authority to the EPA to regulate GHGs, the D.C. Circuit remanded the 2006 Final Rule to the EPA upon its own motion for further consideration of the issues related to GHG emissions in light of *Massachusetts.* The EPA did not act on that remand. Rather, these State and Environmental Petitioners and the EPA negotiated a proposed settlement agreement that set deadlines for the EPA to propose and take final action on (1) a rule under CAA section 111(b) that includes standards of performance for GHGs for new and modified EGUs that are subject to 40 CFR part 60, subpart Da; and (2) a rule under CAA section 111(d) that includes emission guidelines for GHGs from existing EGUs that would have been subject to 40 CFR part 60, subpart Da if they were new sources. Pursuant to CAA section 113(g), the EPA provided for a notice-and-comment opportunity on the proposed settlement agreement and, after reviewing the comments received, finalized the agreement in late 2010.

In June 2012, the D.C. Circuit, in *Coalition for Responsible Regulation* v. *EPA,* upheld the EPA's Endangerment Finding concerning GHGs and the EPA's companion finding that GHGs from motor vehicles contribute to the air pollution that endangers public health and welfare.[67] The Court also upheld standards for motor vehicles that limited GHG emissions.[68] In addition, the Court affirmed the EPA's view that the CAA PSD and title V permitting requirements became applicable to GHG-emitting stationary sources when the EPA regulated GHG emissions from motor vehicles, because PSD and title V are automatically applicable to a pollutant when that pollutant is regulated under any part of the Act. The Court also dismissed challenges to what we refer to as the Timing Decision,[69] which established the January 2, 2011 date when the PSD and title V permitting requirements applied to GHG-emitting stationary sources; and the Tailoring Rule,[70] which is the EPA's common sense approach to phasing in GHG permitting requirements to avoid an initial increase in the number of PSD and title V permit applications that would overwhelm the permitting authorities' administrative capacities.

In June 2012, several companies filed petitions for review of the original proposal for this rulemaking action in the D.C. Circuit. In December 2012, the D.C. Circuit dismissed these petitions on grounds that the challenged proposed rule is not final agency action subject to judicial review.[71]

In April 2013, EPA completed rulemaking to regulate power plants in the Mercury and Air Toxics rule (''MATS'').[72] In this same rulemaking, EPA promulgated revised standards of performance under CAA section 111(b) for criteria pollutant emissions from EGUs.

F. Coordination With Other Rulemakings

EGUs are the subject of several recent CAA rulemakings.[73] In general, most EPA rulemakings affecting the power sector focus on existing sources.

BSER, but we may occasionally refer to it as the ''best demonstrated system.'' In the past, this level of control was frequently referred to as the ''best demonstrated technology'' (BDT).

[63] ''Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971,'' 36 FR 24875 (Dec. 23, 1971) codified at 40 CFR 60.40–46; 36 FR 5931 (Mar. 31, 1971).

[64] ''Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978,'' 44 FR 33580 (June 11, 1979)

[65] ''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 (Feb. 27, 2006).

[66] *State of New York, et al.* v. *EPA, No. 06–1322.* The two groups of petitioners were (1) the States of New York, California, Connecticut, Delaware, Maine, New Mexico, Oregon, Rhode Island, Vermont and Washington; the Commonwealth of Massachusetts; the District of Columbia and the City of New York (collectively ''State Petitioners''); and (2) Natural Resources Defense Council (NRDC), Sierra Club, and Environmental Defense Fund (EDF)(collectively ''Environmental Petitioners'').

[67] *CRR,* 684 F.3d at 102.

[68] ''Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule.'' 75 FR 25324 (May 7, 2010).

[69] ''Interpretation of Regulations that Determine Pollutants Covered by Clean Air Act Permitting Programs.'' 75 FR 17004 (April 2, 2010).

[70] ''Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule.'' 75 FR 31514 (June 3, 2010).

[71] *Las Brisas Energy Center, LLC* v. *Environmental Protection Agency,* No. 12–1248, 2012 U.S. App. LEXIS 25535 (D.C. Cir. Dec. 13, 2012).

[72] ''Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, Final Rulemaking, '' 78 FR 24073 (April 24, 2013).

[73] 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.

Therefore, few interactions are likely between other power sector rules and this rule, which focuses only on new sources.[74]

We note that the EPA recently finalized revisions to the MATS rule as related to new sources.[75] The revised MATS new source emission standards for air toxics and new source performance standards for criteria pollutants, coupled with GHG performance standards in this proposed rule, provide a clear regulatory structure for new fossil fuel-fired generation.

The EPA recognizes that it is important that each of these regulatory efforts achieves its intended environmental objectives in a common-sense, cost-effective manner consistent with the underlying statutory requirements and assures a reliable power system. Executive Order (EO) 13563 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.'' Recent guidance from the Office of Management and Budget's Office of Information and Regulatory Affairs has emphasized the importance of, where appropriate and feasible, the consideration of cumulative effects in regulated industries and the harmonization of rules in terms of both content and timing. We believe that these recent finalized and proposed rules will allow industry to comply with its obligations as efficiently as possible, by making coordinated investment decisions and, to the greatest extent possible, adopting integrated compliance strategies.

G. Stakeholder Input

The EPA has extensively interacted with many different stakeholders regarding climate change, source contributions, and emission reduction opportunities. These stakeholders included industry entities, environmental organizations and many regional, state, and local air quality management agencies, as well as the general public. As part of developing the original proposed rule, the EPA held five listening sessions in February and March 2011 to obtain additional information and input from key stakeholders and the public. Each of the five sessions had a particular target audience; these were the electric power industry, environmental and environmental justice organizations, states and Tribes, coalition groups and the petroleum refinery industry. Each session lasted two hours and featured a facilitated roundtable discussion among stakeholder representatives. The EPA asked key stakeholder groups to identify these roundtable participants in advance of the listening sessions. The EPA accepted comments from the public at the end of each session and via the electronic docket system.[76]

On May 3, 2012, the EPA announced that it would hold two public hearings on the original proposed rule. The hearings were both held on May 24, 2012, in Washington, DC and Chicago, IL. Also on May 3, 2012, the EPA announced an extension of the public comment period for the original proposed rule, until June 25, 2012. The EPA received more than 2.5 million public comments on the original proposed rule.[77] While the Agency is not preparing a RTC document responding to the comments it received as part of that process, the EPA has taken into consideration those comments, as well as information received in the listening sessions, in developing this new proposal.

III. Proposed Requirements for New Sources

This section describes the proposed requirements in this rulemaking for new sources. We describe our rationale for several of these proposed requirements—the applicability requirements, the basis for the standards of performance for fossil-fuel fired boilers, and the basis for the standards of performance for combustion turbines—in Sections V–VIII of this preamble.

A. Applicability Requirements

We generally refer to sources that would be subject to the standards of performance 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 rule, and the requirements for ''new'' sources as defined under the provisions of CAA section 111.

1. Covered EGUs, Generally

Subpart Da currently defines an EGU as a boiler that is: (1) ''capable of combusting'' more than 250 MMBtu/h heat input of fossil fuel,[78] (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'' [79] (that is, to the grid), and (3) ''constructed for the purpose of supplying . . . more than 25 MW net-electric output'' to the grid.[80] We are proposing to define an EGU slightly differently than it is currently defined in subpart Da or in the original proposal for this rulemaking. First, we are proposing to add additional criteria to be met in addition to the ''constructed for the purpose of supplying more than one-third of its potential electric output capacity'' to the grid. One new criterion would be that a unit actually ''supplies more than one-third of its potential electric output'' to the grid. Both criteria would also be used in subparts KKKK and TTTT. Combined with the three year rolling average methodology to determine if the one-third criteria is met (as explained further below), this approach makes it clear that a unit that was not originally constructed to supply more than one-third of its potential electric output to the grid, but does so for one year does not automatically become affected. The EPA believes that coal-fired utility boilers, IGCCs and large NGCC units are constructed with the purpose of supplying more than one-third of their potential electric output to the grid, and, except in rare cases (such as very extended outages), usually do. Small NGCC units and simple cycle combustion turbines that are generally designed for operation during peak demand will usually supply less than one-third of their potential electric output to the grid. Even though these projects are not generally designed to supply more than one-third of their potential electric output to the grid, there can be rare instances when they do. For instance, when a large base load unit in a transmission-constrained area experiences a long, unexpected outage, it may be necessary to operate simple cycle combustion turbines significantly more than anticipated. The EPA believes the combination of the actual sales criteria and the three year rolling average to determine if the sales criteria are met will address this concern. Second, we are proposing to revise the

[74] Other pending EPA regulatory actions in the power sector are discussed in more detail in Chapter 4 of the RIA.

[75] 78 FR 24073.

[76] Comments related to the listening sessions submitted via the electronic docket system are available at *www.regulations.gov* (docket number EPA–HQ–OAR–2011–0090).

[77] Those comments are available at *www.regulations.gov* (docket number EPA–HQ–OAR–2011–0660).

[78] E.g., 40 CFR 60.40Da(a)(1).

[79] 40 CFR 60.41Da (definition of (''Electric utility steam-generating unit'').

[80] *Id.*

third criteria to be met if the EGU is constructed for the purpose of supplying ''more than 219,000 MWh,'' as opposed to ''25 MW,'' net-electrical 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. We are also proposing to revise the averaging period for electric sales from an annual basis to a three-year rolling average for stationary combustion turbines. In addition, we are proposing to add a new applicability criterion that is not currently in subpart Da: EGUs, for which 10 percent or less of the heat input over a three-year period is derived from a fossil fuel, are not subject to any of the proposed CO_2 standards.

For the purposes of this rule, we are proposing several additional changes to the way applicability is currently determined under subpart Da. First, the proposed definition of potential electric output includes ''or the design net electric output efficiency'' as an alternative to the default one-third efficiency value for determining the value of the potential electric output. Next, we are proposing to add ''of the thermal host facility or facilities'' to the definition of net-electric output for determining electric sales with respect to the NSPS. Finally, consistent with our approach in the NSPS part of the MATS rule and the original proposal for this rulemaking, 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'' instead of the existing language ''plus any integrated combustion turbines and fuel cells''. We are also proposing to add the additional language to the definition of IGCC and stationary combustion turbine.

2. CO_2 Emissions Only

This action proposes to regulate covered EGU emissions of CO_2, and not other constituent gases of the air pollutant GHGs. We identify the pollutant we propose to regulate as GHGs, but, again, only CO_2 emissions are subject to the proposed standard of performance. We are not proposing separate emission limits for other GHGs (such as methane (CH_4) or nitrous oxide (N_2O)) as they represent less than 1 percent of total estimated GHG emissions from fossil fuel-fired electric power generating units.

The proposed CO_2 emission standards do not apply a different accounting method for biogenic CO_2 emissions for the purpose of determining compliance with the standards. However, the proposed CO_2 emission standards only apply to new fossil fuel-fired EGUs. Based on the applicability provisions in the proposal, as discussed above, an EGU that primarily fires biomass would not be subject to the CO_2 emission standards. Such units could fire fossil fuels up to 10 percent on a three-year average annual heat input basis (e.g., for start-up and combustion stabilization) without becoming subject to the standards.

Issues related to accounting for biogenic CO_2 emissions from stationary sources are currently being evaluated by the EPA through its development of an Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources (Accounting Framework).[81] In general, the overall net atmospheric loading of CO_2 resulting from the use of a biogenic feedstock by a stationary source, such as an EGU, will ultimately depend on the stationary source process and the type of feedstock used, as well as the conditions under which that feedstock is grown and harvested. In September 2011, the EPA submitted a draft of the Accounting Framework to the Science Advisory Board (SAB) Biogenic Carbon Emissions (BCE) Panel for peer review. The SAB BCE Panel delivered its Peer Review Advisory to the EPA on September 28, 2012.[82] In its Advisory, the SAB recommended revisions to the EPA's proposed accounting approach, and also noted that biomass cannot be considered carbon neutral *a priori,* without an evaluation of the carbon cycle effects related to the use of the type of biomass being considered. The EPA is currently reviewing the SAB peer review report, and will move forward as warranted once the review is complete.

3. Sources Not Subject to This Rulemaking

We are not proposing standards for certain types of sources. These include new steam generating units and stationary combustion turbines that sell one-third or less of their potential output to the grid; new non-natural gas-fired stationary combustion turbines;[83] 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) as discussed below. As a result, under the CAA section 111(a) definitions of ''new source'' and ''existing source,''[84] if those types of sources commence construction or modification, they would not be treated as ''new source[s]'' subject to the standards of performance proposed today, and instead, they would be treated as existing sources.

B. Emission Standards

In this rulemaking, the EPA is proposing NSPS for CO_2 emissions from several subcategories of affected sources, which are new fossil fired EGUs described above in Section III.A.

1. Standards of Performance for Affected Sources

a. Emission Standard

The proposed standard of performance for each subcategory is in the form of a gross energy output-based CO_2 emission limit expressed in units of emissions mass per unit of useful recovered energy, specifically, in pounds per megawatt-hour (lb/MWh). This emission limit would apply to affected sources upon the effective date of the final action. In this notice, we sometimes refer to ''gross energy output'' as ''gross output'' or ''adjusted gross output.''

The subcategories, for which the EPA is proposing separate standards of performance, are (1) natural gas-fired stationary combustion turbines with a heat input rating that is greater than 850 MMBtu/h;[85] (2) natural gas-fired stationary combustion turbines with a heat input rating that is less than or equal to 850 MMBtu/h; and (3) all fossil fuel-fired boilers and IGCC units, which generally are solid-fuel fired.

We are proposing that all affected new fossil fuel-fired EGUs are required to meet an output-based emission rate of a specific mass of CO_2 per MWh of useful output. Specifically, new combustion turbines with a heat input rating greater

[81] The EPA's draft accounting framework is available at *http://www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.*

[82] The text of the SAB Peer Review Advisory is available at *http://yosemite.epa.gov/sab/sabproduct.nsf/0/2f9b572c712ac52e8525783100704886!OpenDocument&TableRow=2.3#2.*

[83] 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).

[84] CAA section 111(a)(2), (6).

[85] 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.

than 850 MMBtu/h would be required to meet a standard of 1,000 lb CO_2/MWh. New combustion turbines with a heat input rating less than or equal to 850 MMBtu/h would be required to meet a standard of 1,100 lb CO_2/MWh. As discussed below, these proposed standards are based on the demonstrated performance of recently constructed NGCC units, which are currently in wide use throughout the country, and are currently the predominant fossil fuel-fired technology for new electric generating units in the near future.

While the EPA is proposing specific standards of performance for each subcategory, we are also taking comment on a range of potential emission limitations. We solicit comment on a range of 950–1,100 lb CO_2/MWh for new stationary combustion turbines with a heat input rating greater than 850 MMBtu/h. We also solicit comment on an emission limitation range of 1,000–1,200 lb CO_2/MWh for new stationary combustion turbines with a heat input rating less than or equal to 850 MMBtu/h. In addition, we solicit comment on an emission limitation for new fossil fuel-fired boilers and IGCC units in the range of 1,000–1,200 lb CO_2/MWh.

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 useful energy output over a rolling 12-operating-month period. In the alternative, we solicit comment on requiring calculation of compliance on an annual (calendar year) period.

b. Gross Output

Subpart Da currently defines ''gross energy output'' from new units as the ''gross electrical or mechanical output from the affected facility minus any electricity used to power the feedwater pumps and any associated gas compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) plus 75 percent of the useful thermal output measured relative to ISO conditions'' [86] [87] (referred to in today's document as ''adjusted gross output''). The current criteria pollutant emission standards for new subpart Da units were developed by analyzing the gross emission rates of PC and CFB facilities, and were finalized on February 16, 2013 (77 FR 9304). In that rulemaking, we applied the same standards to traditional coal-fired and IGCC EGUs. The adjusted gross output definition accounts for the largest gas compressors at an IGCC facility. Consequently, IGCC facilities complying with the NSPS requirements would emit at approximately the same net output based emissions rate (i.e., gross output minus auxiliary power requirements) as a comparable traditional coal-fired EGU. Therefore, with the definition of gross energy output for criteria pollutant emission standards (i.e., adjusted gross output), both IGCC and traditional coal-fired EGUs that have the same gross energy output-based emissions rate would have a similar net output-based emissions rate. If we did not include the parasitic load from the primary gas compressors when determining the gross emissions rate of an IGCC facility, it would emit more pollutants to the atmosphere than a traditional coal-fired EGU when complying with the criteria pollutant NSPS.

In contrast, in the April 2012 proposal, we proposed a definition of gross output as ''the gross electrical or mechanical output from the unit plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output or to enhance the performance of the unit *(i.e.,* steam delivered to an industrial process).'' This definition was appropriate since NGCC was the BSER for the combined subcategory and auxiliary loads associated with feedwater pumps and associated compressors (air separation unit main compressor, oxygen compressor, and nitrogen compressor) are not relevant to the gross efficiency of an NGCC. However, we requested comment on requiring the use of net output based standards. Part of the rationale behind the use of net output-based standards is that the use of a gross output-based standard as defined could have potentially driven the installation of electrically driven feed pumps instead of steam driven feed pumps at a steam generating unit, even though from an overall net efficiency basis it may be more efficient to use steam-driven feed pumps.

After further consideration and because many of the proposed IGCC facilities are actually co-production facilities (i.e., they produce useful byproducts and chemicals along with electricity), we have concluded that measuring the electricity used by the primary gas compressors associated with electricity production at IGCC facilities could be more challenging to implement.

Therefore, we are proposing to define the gross energy output for traditional steam generating units to include the electricity measured at the generator terminals minus electric power used to run the feedwater pumps, and to define the gross electric output for IGCC and subpart KKKK affected facilities to include the electricity measured at the generator terminals. We are considering and requesting comment on (1) whether the definition of ''gross energy output'' in subpart Da for GHGs should be consistent with the current definition in subpart Da for criteria pollutants, (2) whether we should adopt the proposed definition of ''gross energy output'', and (3) whether the definition should be the same for both traditional and IGCC facilities. We seek comment on how to account for energy consumption associated with products other than electricity and useful thermal output created at a poly-generation facility and the impact of that energy use on the numerical emissions standard, all of which is relevant to possible adoption of an adjusted gross output definition.

We are also considering and requesting comment on using net-output based standards either as a compliance alternative for, or in lieu of, gross-output based standards, including whether we should have a different approach for different subcategories. In the compliance alternative approach, owners/operators would elect to comply with either a gross-output based standard or an alternate net-output based standard. As described in the original proposal for this rulemaking, net output is the combination of the gross electrical output of the electric generating unit minus the parasitic (i.e., auxiliary) power requirements. A parasitic load for an electric generating unit is any of the loads or devices powered by electricity, steam, hot water, or directly by the gross output of the electric generating unit that does not contribute electrical, mechanical, or thermal output. In general, less than 7.5 percent of non-IGCC and non-CCS coal-fired station power output, approximately 15 percent of non-CCS IGCC-based coal-fired station power output and about 2.5 percent of non-CCS combined cycle station power output is used internally by parasitic energy demands, but the amount of these parasitic loads vary from source to source. Reasons for using net output include (1) recognizing the efficiency gains of selecting EGU designs and control equipment that require less auxiliary power, (2) selecting fuels that require less emissions control equipment, and (3) recognizing the environmental benefit of higher efficiency motors, pumps, and fans.

[86] 40 CFR 60.41Da.

[87] International Standards Organization Metric (ISO) Conditions are 288 Kelvin (15 °C), 60 percent relative humidity, and 101.325 kilopascals (kPa) pressure.

While the EPA has concluded that the net power supplied to the end user is a better indicator of environmental performance than gross output from the power producer, we only have CEMS emissions data reported on a gross output basis because that is the way the data is currently reported under 40 CFR part 75. As noted, switching from gross output to net or adjusted gross output would have little or no impact on the required rates for gas-fired NGCC plants, which are likely to be the dominant fossil fuel-fired technology for new intermediate or base load power generation. Since the change would have little impact on these units in terms of environmental performance, the EPA has proposed to use a standard consistent with current reporting protocols. However, as is noted in Table 4, the use of net instead of gross output could have a much larger impact on coal-fired power plants.

TABLE 4—SUBPART DA EMISSION RATES [88]

Gross output based standard	Approximate equivalent adjusted gross output based standard	Approximate equivalent net output based standard
450 kg/MWh (1,000 lb/MWh)	510 kg/MWh (1,100 lb/MWh)	560 kg/MWh (1,200 lb/MWh).
500 kg/MWh (1,100 lb/MWh)	570 kg/MWh (1,300 lb/MWh)	620 kg/MWh (1,400 lb/MWh).
540 kg/MWh (1,200 lb/MWh)	610 kg/MWh (1,300 lb/MWh)	670 kg/MWh (1,500 lb/MWh).

TABLE 5—SUBPART KKKK EMISSION RATES

Gross output based standard	Approximate equivalent net output based standard
430 kg/MWh (950 lb/MWh).	440 kg/MWh (970 lb/MWh).
450 kg/MWh (1,000 lb/MWh).	460 kg/MWh (1,000 lb/MWh).
500 kg/MWh (1,100 lb/MWh).	510 kg/MWh (1,100 lb/MWh).
540 kg/MWh (1,200 lb/MWh).	560 kg/MWh (1,200 lb/MWh).

Requiring or including an optional net-output based standard would provide more operational flexibility and expand the technology options available to comply with the standard for coal-fired PC and CFB EGUs.

In addition, we are proposing that with respect to CO_2 emissions, 75 percent credit is the appropriate discount factor for useful thermal output. However, we are requesting comment on a range of two-thirds to three-fourths credit for useful thermal output in the final rule.

2. 84-Operating-Month Rolling Average Compliance Option

We also propose an 84-operating-month rolling average compliance option that would be available for affected subpart Da boilers and IGCC facilities. The EPA suggests that this 84-operating-month rolling average compliance option will offer operational flexibility and will tend to dampen short-term emission excursions, which may be warranted especially at the initial startup of the facility and the CCS system.

Thus, under our proposed approach, new fossil fuel-fired boilers and IGCC units would be required, based on the performance of currently available CCS technology, to meet a standard of 1,100 lb CO_2/MWh on a 12-operating-month rolling average, or alternatively a lower—but equivalently stringent—standard on an 84-operating-month rolling average, which we propose as between 1,000 lb CO_2/MWh and 1,050 lb CO_2/MWh. The EPA has previously offered sources optional, longer-term emission standards that are discounted from the primary emissions standard in combination with a longer averaging period. We are requesting comment on the appropriate numerical standard such that the 84-operating-month standard would be as stringent as or more stringent than the 12-operating-month standard. We also request comment on whether owners/operators electing to comply with the 84-operating-month standard should also be required to comply with a maximum 12-operating-month standard. This standard would be between the otherwise applicable proposed 1,100 lb CO_2/MWh standard and an emissions rate of a coal-fired EGU without CCS (e.g., 1,800 lb CO_2/MWh), and we solicit comment on what the standard should be. This shorter term standard would facilitate enforceability and assure adequate emission reductions.

We have concluded that this alternative compliance option is not necessary for new stationary combustion turbine EGUs, as they should be able to meet the proposed performance standard with no need for add-on technology. We seek comment on all other aspects of this 84-operating-month rolling averaging compliance option.

3. Combined Heat and Power

To recognize the environmental benefit of reduced electric transmission and distribution losses of CHP, we are proposing that CHP facilities where at least 20.0 percent of the total gross useful energy output consists of electric or direct mechanical output and 20.0 percent of the total gross useful energy output consists of useful thermal output on a rolling three calendar year basis receive similar credit as currently in subpart Da and the proposed amendments to subpart KKKK (77 FR 52554). Specifically, the measured electric output would be divided by 0.95 to account for a five percent avoided energy loss in the transmission of electricity. The minimal electric and thermal output requirements are to avoid owners/operators from selling trivial amounts of thermal output and claiming a line loss benefit when in reality they are similar to a central power station.

Actual transmission and distribution losses vary from location to location, but we propose that this 5 percent of actual MWh represents a reasonable average amount for the avoided transmission and distribution losses for CHP facilities. Note that we propose to limit this 5 percent adjustment to facilities for which the useful thermal output is at least 20 percent of the total output.

C. Startup, Shutdown, and Malfunction Requirements

1. Startups and Shutdowns

Consistent with *Sierra Club* v. *EPA,*[89] 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 and, for the reasons explained below has not proposed alternate standards for those periods. In the compliance calculation, periods of startup and shutdown are included as periods of partial load. To establish the proposed NSPS's output-based CO_2 standard, we accounted for periods of startup and shutdown by incorporating them as periods of partial load operation. As noted above, the proposed

[88] Rounding to two significant figures results in the same standard in units of lb/MWh in some cases.

[89] 551 F.3d 1019 (D.C. Cir. 2008).

method to calculate compliance is to sum the emissions for all operating hours and to divide that value by the sum of the electrical 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, that fuel is combusted and emissions monitors are not out-of-control, as well as 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 during startup or shutdown periods, the impact of these periods on the total average is expected to be minimal. Periods of startup and shutdown will be short, relative to total operating time. Since we are primarily concerned with overall environmental performance over extended periods of time, incorporating relatively short periods of partial load is believed to have a negligible effect on the performance of the source with respect to long-term efficiency.

We solicit comment on any alternative to our proposal that the periods of startup and shutdown be included as periods of partial load in the 12- and 84-operating-month rolling averaging compliance option.

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 a sudden, infrequent, and not reasonably preventable failure of air pollution control and monitoring 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 operations 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 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. Applying the concept of ''the application of the best system of emission reduction'' to periods during which a source is malfunctioning presents difficulties. The ''application of the best system of emission reduction'' is more appropriately understood to include operating units in such a way as to avoid malfunctions.

Further, accounting for malfunctions 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, the goal of a source that uses the best system of emission reduction is to operate in such a way as to avoid malfunctions of the source and accounting for malfunctions could lead to standards that are significantly less stringent than levels that are achieved by a well-performing non-malfunctioning source. The EPA's approach to malfunctions is consistent with 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 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 (definition of malfunction).

Finally, the EPA recognizes that even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause a violation of the relevant emission standard. (*See, e.g.,* State Implementation Plans: Response to Petition for Rulemaking; Finding of Excess Emissions During Periods of Startup, Shutdown, and Malfunction; Proposed Rule, 78 FR 12460 (Feb. 22, 2013): (State Implementation Plans: Policy Regarding Excessive Emissions During Malfunctions, Startup, and Shutdown (Sept. 20, 1999); Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions (Feb. 15, 1983)). The EPA is therefore proposing to add an affirmative defense to civil penalties for violations of emission standards that are caused by malfunctions. See 40 CFR 60.10042 (defining ''affirmative defense'' to mean, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding). We also are proposing other regulatory provisions to specify the elements that are necessary to establish this affirmative defense; the source must prove by a preponderance of the evidence that it has met all of the elements set forth in § 60.5530. (See 40 CFR 22.24). The criteria are designed in part to ensure that the affirmative defense is available only where the event that causes a violation of the emission standard meets the narrow definition of malfunction in 40 CFR 60.2 (sudden, infrequent, not reasonably preventable and not caused by poor maintenance and or careless operation). For example, to successfully assert the affirmative defense, the source must prove by a preponderance of the evidence that the violation ''[w]as caused by a sudden, infrequent, and unavoidable failure of air pollution control, process equipment, or a process to operate in a normal or usual manner . . .'' The criteria also are designed to ensure that steps are taken to correct the malfunction, to minimize emissions in accordance with § 60.5530 and to prevent future malfunctions. For example, the source must prove by a preponderance of the evidence that

''[r]epairs were made as expeditiously as possible when a violation occurred . . .'' and that ''[a]ll possible steps were taken to minimize the impact of the violation on ambient air quality, the environment and human health . . .'' In any judicial or administrative proceeding, the Administrator may challenge the assertion of the affirmative defense and, if the respondent has not met its burden of proving all of the requirements in the affirmative defense, appropriate penalties may be assessed in accordance with section 113 of the CAA (see also 40 CFR 22.27).

The EPA included an affirmative defense in the proposed rule in an attempt to balance a tension, inherent in many types of air regulation, to ensure adequate compliance while simultaneously recognizing that despite the most diligent of efforts, emission standards may be violated under circumstances beyond the control of the source. The EPA must establish emission standards that ''limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis.'' 42 U.S.C. 7602(k) (defining ''emission limitation'' and ''emission standard''). *See generally Sierra Club* v. *EPA,* 551 F.3d 1019, 1021 (D.C. Cir. 2008) Thus, the EPA is required to ensure that section 111 emissions standards are continuous. The affirmative defense for malfunction events meets this requirement by ensuring that even where there is a malfunction, the emission standard is still enforceable through injunctive relief. The United States Court of Appeals for the Fifth Circuit recently upheld the EPA's view that an affirmative defense provision is consistent with section 113(e) of the Clean Air Act. *Luminant Generation Co. LLC* v. *United States EPA,* 2013 U.S. App. LEXIS 6397 (5th Cir. Mar. 25, 2013) 699 F3d. 427 (5th Cir. Oct. 12, 2012) (upholding the EPA's approval of affirmative defense provisions in a CAA State Implementation Plan). While ''continuous'' standards, on the one hand, are required, there is also case law indicating that in many situations it is appropriate for the EPA to account for the practical realities of technology. For example, in *Essex Chemical* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), the D.C. Circuit acknowledged that in setting standards under CAA section 111 ''variant provisions'' such as provisions allowing for upsets during startup, shutdown and equipment malfunction ''appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the 'never to be exceeded' standard currently in force.'' *See* also, *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973). Although due to intervening case law such as *Sierra Club* v. *EPA* and the CAA 1977 amendments (which added the ''continuous'' requirement of 42 U.S.C. 7602(k)) these cases are no longer good law on whether EPA can exempt malfunctions from liability, their core principle remains valid: regulatory accommodation is appropriate where a standard cannot be achieved 100 percent of the time due to circumstances out of the control of the owner/operator of the source, and a system that incorporates some level of flexibility is reasonable. The affirmative defense simply provides for a defense to civil penalties for violations that are proven to be beyond the control of the source. By incorporating an affirmative defense, the EPA has formalized its approach to malfunctions. In a Clean Water Act setting, the Ninth Circuit required this type of formalized approach when regulating ''upsets beyond the control of the permit holder.'' *Marathon Oil Co.* v. *EPA,* 564 F.2d 1253, 1272–73 (9th Cir. 1977). *See also, Mont. Sulphur & Chem. Co.* v. *United States EPA,* 666 F.3d. 1174 (9th Cir. 2012) (rejecting industry argument that reliance on the affirmative defense was not adequate). *But see, Weyerhaeuser Co.* v. *Costle,* 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal approach is adequate). The affirmative defense provisions give the EPA the flexibility to both ensure that its emission standards are ''continuous'' as required by 42 U.S.C. 7602(k), and account for unplanned upsets and thus support the reasonableness of the standard as a whole.

We propose that these same requirements, an affirmative defense to civil penalties for violations of emission limits that are caused by malfunctions, would apply to both the 12-operating-month standard and the 84-operating-month rolling average compliance option; however, we will take comment on whether it is appropriate to have an affirmative defense for the 84-operating-month rolling average portion of that compliance option, given that we would expect malfunctions to only impact shorter averaging periods, and the longer the compliance period, the less likely malfunction events are to impact a source's ability to meet the standard.

D. Continuous Monitoring Requirements

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 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/hr).

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 of 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 of 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 §§ 75.53(g) and (h). The electronic portion of the monitoring plan would be submitted to the EPA's Clean Air Markets Division (CAMD) using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. The hard copy portion of the plan would be sent to the applicable State and EPA Regional office. Further, all monitoring systems used to determine the CO_2 mass emission rates would have to be certified according to § 75.20 and section 6 of Appendix A to part 75 within the 180-day window of time allotted under § 75.4(b), and would be required to meet the applicable on-going quality assurance procedures in Appendices B and D of part 75.

The proposed rule would require all valid data collected and recorded by the monitoring systems (including data recorded during startup, shutdown, and malfunction) to be used in assessing compliance. Failure to collect and record required data is a violation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities that temporarily interrupt the measurement of stack emissions (e.g., calibration error tests, linearity checks, and required zero and span

adjustments). An affirmative defense to civil penalties for malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied.

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.

The following variations from and additions to the basic part 75 monitoring would be required:

- If you determine compliance using CEMS, you would be required to use a laser device to measure the stack diameter at the flow monitor and the reference method sampling locations prior to the initial setup (characterization) of the flow monitor. For circular stacks, you would need to make measurements of the diameter at 3 or more distinct locations and average the results. For rectangular stacks or ducts, you would need to make measurements of each dimension (i.e., depth and width) at 3 or more distinct locations and average the results. If the flow rate monitor or reference method sampling site is relocated, you would repeat these measurements at the new location.
- If you elect to use Method 2 in Appendix A–1 of part 60 to perform the required relative accuracy test audits (RATAs) of the part 75 flow rate monitoring system, you would have to use a calibrated Type-S pitot tube or pitot tube assembly. Use of the default Type-S pitot tube coefficient would not be permitted.
- If your EGU combusts natural gas and/or fuel oil and you elect to measure the CO_2 mass emissions rate using Equation G–4 in Appendix G of part 75, you would be allowed to determine site-specific carbon-based F-factors using Equation F–7b in section 3.3.6 of Appendix F of part 75, and you could use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

Today's proposed rule includes the following special compliance provisions for units with common stack or multiple stack configurations; these provisions are consistent with § 60.13(g):

- If two or more of your EGUs share a common exhaust stack, are subject to the same emission limit, and you are required to (or elect to) determine compliance using CEMS, you would be allowed to monitor the hourly CO_2 mass emission rate at the common stack instead of monitoring each EGU separately. If this option is chosen, the hourly gross electrical load (or steam load) would be the sum of the hourly loads for the individual EGUs and the operating time would be expressed as ''stack operating hours'' (as defined in 40 CFR 72.2). Then, if compliance with the applicable emission limit is attained at the common stack, each EGU sharing the stack would be in compliance with the CO_2 emissions limit.
- If you are required to (or elect to) determine compliance using CEMS and the effluent from your EGU discharges to the atmosphere through multiple stacks (or, if the effluent is fed to a stack through multiple ducts and you choose to monitor in the ducts), you would be required to monitor the hourly CO_2 mass emission rate and the ''stack operating time'' at each stack or duct separately. In this case, compliance with the applicable emission limit would be determined by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross output for the unit.

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 §§ 75.10(e) and 75.20(d), to help meet this proposed data capture requirement.

E. Emissions Performance Testing Requirements

In accordance with § 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 § 75.4(b) allotted for initial certification of the monitoring systems expires (whichever date is earlier). For EGUs subject to the 450 kg/MWh (1,000 lb/MWh) standard or the 500 kg/MWh (1,100 lb/MWh) emission standard, 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 § 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. For EGUs that combust coal and/or petroleum coke and whose owners or operators elect to comply with the alternative 84-operating-month rolling average emissions standard, the first month in the compliance period would be the month in which emissions reporting is required to begin under § 75.64(a).

F. Continuous Compliance Requirements

Today's proposed rule specifies that compliance with the 1,000 lb/MWh (450 kg/MWh) and 1,100 lb/MWh (500 kg/MWh) CO_2 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 either the initial 12- or 84-operating-month compliance period would be the month in which reporting of emissions data is required to begin under § 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- or 84-operating-month period. Affected EGUs would continue to be subject to the standards and maintenance requirements in the section 111 regulatory general provisions contained in 40 CFR Part 60, subpart A.

G. Notification, Recordkeeping, and Reporting Requirements

Today's proposed rule would require an EGU owner or operator to comply with the applicable notification requirements in §§ 75.61, 60.7(a)(1) and (a)(3) and 60.19. 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).

For EGU owners or operators who would elect to comply with the 84-operating-month rolling average emissions standard, records must be kept for 10 years. All other records would be kept for a period of three years. All required records would be kept on-site for a minimum of two years, after which the records could be maintained off-site.

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 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 selected data elements that pertain to compliance under this rule, and that serve the purpose of traditional excess emissions reports, to be reported periodically using ECMPS.

Specifically, for EGU owners/operators who would comply with a 12-operating-month rolling average standard, quarterly electronic ''excess emissions'' reports must be submitted, within 30 days after the end of each quarter. The first report would be for the quarter that includes the final (12th) operating month of the initial 12-operating-month compliance period. For that initial report and any subsequent report in which the twelfth operating month of a compliance period (or periods) occurs during the calendar quarter, the average CO_2 mass emissions rate (kg/MWh) would be reported for each compliance period, along with the dates (year and month) of the first and twelfth operating months in the compliance period and the percentage of valid CO_2 mass emission rates obtained in the compliance period. The dates of the first and last operating months in the compliance period would clearly bracket the period used in the determination, which facilitates auditing of the data. 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. If there are no compliance periods that end in the quarter, a definitive statement to that effect would be included in the report. If one or more compliance periods end in the quarter but there are no excess emissions, a statement to that effect would be included in the report.

For EGU owners or operators that would comply with an 84-operating-month rolling average basis, quarterly electronic ''excess emissions'' reports would be submitted, within 30 days after the end of each quarter. The first report would be for the quarter that includes the final (60th) operating month of the initial 84-operating-month compliance period. For that initial report and any subsequent report in which the sixtieth operating month of a compliance period (or periods) occurs during the calendar quarter, the average CO_2 mass emissions rate (kg/MWh) must be reported for each compliance period, along with the dates (year and month) of the first and sixtieth operating months in the compliance period and the percentage of valid CO_2 mass emission rates obtained in the compliance period. The dates of the first and last operating months in the compliance period would clearly bracket the period used in the determination, which facilitates auditing of the data. Reporting of 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. If there are no compliance periods that end in the quarter, a definitive statement to that effect would be included in the report. If one or more compliance periods end in the quarter but there are no excess emissions, a statement to that effect would be included in the report.

Currently, ECMPS is not programmed to receive excess emission report information from EGUs. However, we will make the necessary modifications to the system in order to fully implement the reporting requirements of this rule upon promulgation.

For EGU owners or operators that would assert an affirmative defense for a failure to meet a standard due to malfunction, the owner or operator must follow the reporting requirements for affirmative defense. Those requirements are found in 40 CFR 60.5530. The report to the Administrator, with all necessary supporting documentation, explains how the source has met the requirements set forth in subparts Da, KKKK, and TTTT to assert affirmative defense. This report must be submitted on the same schedule as the next quarterly report required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If the quarterly report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second quarterly report due after the initial occurrence of the violation of the relevant standard.

IV. Rationale for Reliance on Rational Basis To Regulate GHGs From Fossil-Fired EGUs

A. Overview

In our original proposal, we proposed and solicited comment on what basis we are required to have concerning the health and welfare impacts of GHG emissions from fossil-fuel fired power plants in order to regulate those emissions under CAA section 111. However, we took the position that we are not required to make findings that GHGs from fossil-fired power plants ''cause [ ], or contribute [ ] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare,'' under CAA section 111(b)(1)(A).

We have reconsidered that proposal in light of the numerous comments we received. In today's document, we propose that under section 111, the EPA is required to have a rational basis for

promulgating standards for GHG emissions from electricity generating plants, and that the EPA has such a basis because the EPA has already determined that GHG emissions may reasonably be anticipated to endanger public health and welfare, and because electricity generating plants, as an industry, constitute, by a significant margin, the largest emitters in the inventory. In the April 2012 proposal, the EPA discussed whether CAA section 111 requires that the EPA issue, as a prerequisite for this rulemaking, another ''endangerment'' finding. After reviewing the comments, recent scientific developments, the amount of emissions from the power plant sector, and the case law, the EPA has concluded that even if section 111 requires an endangerment finding, the rational basis described in today's action would qualify as an endangerment finding as well.

As related matters, in this notice, we are proposing to establish regulatory requirements for CO_2 emissions of affected units, which are included in source categories (both steam-generating units and turbines) that the EPA already listed under CAA section 111(b)(1)(A) for regulation under CAA and we are not proposing a listing of a new source category. We are, however, proposing to subcategorize different sets of sources, and establish different CO_2 standards of performance for them, in accordance with CAA section 111(b)(2). To avoid confusion, we are proposing to codify the CO_2 standards of performance in the same subparts—Da and KKKK, depending on the types of units—that currently include the standards of performance for conventional pollutants. We are also co-proposing, in the alternative, to codify the CO_2 standards in a new subpart, TTTT, as we proposed in the original proposal for this rulemaking in April, 2012.[90]

B. Climate Change Impacts From GHG Emissions; Amounts of GHGs From Fossil Fuel-Fired EGUs

In 2009, the EPA Administrator issued the Endangerment Finding under CAA section 202(a)(1). With the Endangerment Finding, 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, and focused on public health and public welfare impacts within the United States. 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. These adverse effects of GHGs on public health and welfare, and the amounts of GHGs emitted by fossil fuel-fired EGUs are briefly summarized in the Section II of this preamble and described in more detail in the RIA, and need not be recited here.

C. CAA Section 111 Requirements

To review the key CAA section 111 requirements: CAA section 111(b)(1)(A), by its terms, requires that the Administrator publish (and from time to time thereafter shall revise) a list of categories of stationary sources. He shall include a category of sources in such list if in his judgment it causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

CAA section 111(b)(1)(B) goes on to provide that after listing the source category, the EPA must promulgate regulations ''establishing federal standards of performance for new sources within such category.'' In turn, CAA section 111(a)(1) defines a ''standard of performance'' as a ''standard for emissions of air pollutants which reflects the degree of emission reduction which (taking into account * * * cost * * * and any nonair quality health and environmental impact and energy requirements) . . . has been adequately demonstrated.'' CAA section 111(b)(2) provides that ''The Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.''

D. Interpretation of CAA Section 111 Requirements

CAA section 111(b)(1)(A) requires the EPA to list a source category if it contributes significantly to air pollution that endangers public health or welfare. The EPA must necessarily conduct this listing by making determinations as to the health or welfare impacts of the pollution to which the source category's pollutants contribute, and as to the significance of the amount of such contribution. However, by the terms of CAA section 111(b)(1)(A), the EPA may make these determinations on the basis of the impacts of the air pollution as a whole to which the source category's pollutants, taken as a whole, contribute. Nothing in CAA section 111(b)(1)(A) requires that the EPA make separate determinations for each type of pollution or each pollutant.

After listing a source category, the EPA must proceed to promulgate standards of performance for the source category's pollutants under CAA section 111(b)(1)(B) and 111(a)(1). However, nothing in those provisions requires that, at the time when the EPA promulgates the standards of performance for the individual pollutants, the EPA must make a determination as to the health or welfare effects of those particular pollutants or as to the significance of the amount of the source category's emissions of those pollutants. Clearly, CAA section 111 does not by its terms require that as a prerequisite for the EPA to promulgate a standard of performance for a particular pollutant, the EPA must first find that the pollutant causes or contributes significantly to air pollution that endangers public health or welfare. The lack of any such requirement contrasts with other CAA provisions that do require the EPA to make endangerment and cause-or-contribute findings for the particular pollutant that the EPA regulates under those provisions. *E.g.,* CAA sections 202(a)(1), 211(c)(1), 231(a)(2)(A).

The lack of any express requirement in CAA section 111 addressing whether and how the EPA is to evaluate emissions of a particular pollutant from the listed source category as a prerequisite for promulgation of a standard of performance is properly viewed as a statutory gap that requires the EPA to make what we refer to as a *Chevron* step 2 interpretation. Under the U.S. Supreme Court's 1984 decision in *Chevron U.S.A. Inc.* v. *NRDC,*[91] to interpret how a statute applies to a particular question, an agency must, at Step 1, determine whether Congress's intent as to the specific question is clear, and, if so, the agency must give effect to that intent. If congressional intent is not clear, then the agency, at Step 2, has discretion to fashion an interpretation that is a reasonable construction of the statute.[92] In this

[90] It should be noted that CAA section 111 clearly applies to GHGs. The U.S. Supreme Court has made this clear because (i) section 111 applies to ''any air pollutant,'' CAA section 111(a)(3), *see* section 111(d)(1)(A) (exempting, for purposes of section 111(d), certain air pollutants); and in *Massachusetts* v. *EPA,* 549 U.S. 497 (2007), the Supreme Court held that the term ''air pollutant,'' as defined under CAA section 302(g), includes GHGs; and (ii) in *American Electric Power Company* v. *Connecticut,* 131 S.Ct. 2527 (2011), the Supreme Court based its holding 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'' on the grounds that CAA section 111 ''provides a means to seek limits on emissions of carbon dioxide from domestic power plants * * *.'' *Id.* at 2538.

[91] 467 U.S. 837 (1984).

[92] *Id.* at 842–43.

case, the EPA is authorized to develop a reasonable interpretation.

Our interpretation is that in order to promulgate a section 111 standard of performance for a particular pollutant, we do not need to make a pollutant-specific endangerment finding, but instead must demonstrate a rational basis for controlling the emissions of the pollutant. That rational basis may be based on information concerning the health and welfare impacts of the air pollution at issue, and the amount of contribution that the source category's emissions make to that air pollution.

Commenters on the April 2012 proposal stated that the EPA is required to make an endangerment finding for CO_2 because when the EPA listed this source category, it was on the basis of other pollutants, and not CO_2. However, to reiterate, CAA section 111(b)(1)(A) by its terms requires that the EPA ''shall publish (and from time to time thereafter, shall revise) a list of categories of stationary sources,'' and that the EPA shall list ''a category of sources'' based on the EPA's judgment that the category ''causes, or contributes significantly to, air pollution'' that endangers public health or welfare. Thus, this provision requires that the EPA make the listing decision on a category basis, and not on a pollutant-by-pollutant basis. That is, this provision does not require that the EPA establish separate lists of source categories, with each list covering a different pollutant. Therefore, this provision does not require that the EPA make an endangerment finding on a pollutant by pollutant basis.

Commenters on the April 2012 proposal stated that the EPA was required to make an endangerment finding because by creating the new subpart TTTT in 40 CFR Part 60, the EPA was listing a new source category that included the affected units. However, in neither the original April 2012 proposal nor this new proposal has EPA proposed to list a new source category. The EPA initially included fossil fuel-fired electric steam generating units (which included boilers) in a category that it listed under section 111(b)(1)(A) [93] and the EPA promulgated the first set of standards of performance for this source category in 1971, which the EPA codified in subpart D.[94] Subsequently, the EPA included fossil fuel-fired combustion turbines in a category that the EPA listed under section 111(b)(1)(A),[95] and the EPA promulgated standards of performance for this source category in 1979, which the EPA codified in subpart GG.[96]

The EPA has revised those regulations, and in some instances, has revised the codifications (that is, the 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.[97] 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.[98] None of these rulemakings, including the revised codifications, however, constituted a new listing under CAA section 111(b)(1)(A).

In today's rulemaking, the EPA is promulgating new standards of performance for CO_2 emissions from certain sets of sources, e.g., steam-generating boilers and turbines. Moreover, we are establishing different requirements for different sets of sources, including steam-generating boilers as well as smaller and larger combustion turbines, in accordance with CAA section 111(b)(2). That provision authorizes the EPA to ''distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing . . . standards [of performance.]''

In today's rulemaking, we are including a proposal and, in the alternative, a co-proposal, which take two different approaches to the source categories and their codification.[99] Our proposal is to codify the new CO_2 standards in the same subparts in which the standards of performance for conventional pollutants are codified. Thus, we propose to codify the GHG standards for steam-generating boilers as a new section in subpart Da, and the GHG standards for combustion turbines as new sections in subpart KKKK. 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 EPA has already listed, or revise the codification of the new source requirements for those categories in subparts Da, GG, and KKKK. Under this proposal, the establishment of different requirements for different sets of sources—for example, coal-fired power plants, larger NGCC plants, and smaller NGCC plants—constitute subcategorizations within the existing categories.

In the alternative, we co-propose to combine the two source categories—again, steam-generating boilers and combustion turbines—for purposes of regulating CO_2 emissions (but not for regulating emissions of conventional pollutants), and to codify all of the proposed regulatory requirements in a new subpart, TTTT.[100] This category, created by combining two existing categories, cannot be considered a new source category that EPA is placing on the list of categories for regulation under CAA section 111(b)(1)(A). Under this co-proposal, the establishment of different requirements for different sets of sources continues to constitute subcategorizations within the existing category.

We solicit comment on the relative merits of each approach. In particular we seek comment on whether the co-proposal to combine the categories and codify the GHG standards for all new affected sources in subpart TTTT will offer any additional flexibility for any future emission guidelines for existing sources, for example, by facilitating a system-wide approach, such as emission rate averaging, that covers fossil-fuel

[93] ''Air Pollution Prevention and Control: List of Categories of Stationary Sources,'' 36 FR 5931 (March 31, 1971).

[94] ''Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971,'' 36 FR 24875 (Dec. 23, 1971) codified at 40 CFR 60.40–46; 36 FR 5931 (Mar. 31, 1971).

[95] 42 FR 53657 (Oct. 3, 1977).

[96] ''Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978,'' 44 FR 33580 (June 11, 1979).

[97] 44 FR 33580 (June 11, 1979).

[98] 71 FR 38497 (July 6, 2006), as amended at 74 FR 11861 (Mar. 20, 2009).

[99] In the original proposal for this rulemaking, the EPA proposed to create within 40 CFR part 60 a new subpart that would include GHG emission regulatory requirements for electric utility steam generating units (i.e., boilers and IGCC units), whose conventional pollutant regulatory requirements are codified under subpart Da; as well as stationary combustion turbines that generate electricity for sale and meet certain size and operational criteria, conventional pollutant regulatory requirements are codified under subpart KKKK. The EPA proposed to number this newly created subpart as subpart TTTT. The EPA explained that combining the GHG regulatory requirements for those sources in TTTT was appropriate because the EPA was establishing the same limit for all those sources based on the same BSER, which was NGCC. 77 FR 22410/2–22411/3.

[100] Under this co-proposal, these regulatory requirements are substantively the same as the requirements proposed for inclusion in subparts Da and KKKK, and are simply collected in a separate subpart, TTTT.

fired steam generating units and combustion turbines.

E. Rational Basis To Promulgate Standards for GHGs From Fossil-Fired EGUs

In this rulemaking, the EPA has a rational basis for concluding that emissions of CO_2 from fossil-fired power plants, which are the major U.S. source of greenhouse gas air pollution, merits taking action under CAA section 111. As noted, in 2009, the EPA made a finding that GHG air pollution may reasonably be anticipated to endanger public health or welfare, and in 2010, the EPA denied petitions to reconsider that finding. The EPA extensively reviewed the available science concerning GHG pollution and its impacts in taking those actions. In 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the finding and denial of petitions to reconsider. In addition, assessments from the NRC and the IPCC, published in 2010, 2011, and 2012 lend further credence to the validity of the Endangerment Finding. As discussed below, no information that commenters have presented or that the EPA has reviewed provides a basis for rescinding that finding. In addition, as noted, the high level of GHG emissions from the fossil-fired EGUs makes clear that it is rational for the EPA to regulate GHG emissions from this sector. This information amply supports that the EPA has a rational basis for promulgating regulations under CAA section 111 designed to address GHG air pollution.

Our conclusion is consistent with the case law handed down by the D.C. Circuit. In its 1980 decision in *National Lime Association* v. *EPA,*[101] the Court upheld EPA's determination that lime manufacturing plants emit particulates that contribute significantly to air pollution that endangers public health or welfare. The Court noted that (i) EPA's basis was its prior determination that ''the significant production of particulate emissions . . . cause[s] or contribute[s] to air pollution (which may reasonably be anticipated to endanger public health or welfare);'' and (ii) ''[t]he Agency has made this determination for purposes of establishing national primary and secondary ambient air quality standards under [CAA section 109].'' The Court held:

> We think the danger of particulate emissions' effect on health has been sufficiently supported in the Agency's (and its predecessor's) previous determinations to provide a rational basis for the Administrator's finding in this case.[102]

Similarly, in *National Asphalt Pavement Ass'n* v. *Train,*[103] the D.C. Circuit upheld a determination by the EPA that asphalt cement plants contribute significantly to particulate matter air pollution that endangers public health and welfare. The Court indicated that the EPA's determination that particulate matter endangers is valid simply on grounds that the EPA established a NAAQS for that pollutant.[104]

These cases support our relying primarily on the analysis and conclusions in our previous Endangerment Finding, and the subsequent assessments, as providing a rational basis for our decision to impose standards of performance on GHG emissions from fossil-fuel fired EGUs.

In comments on the original proposal, commenters state that because the proposed rulemaking limits emissions of only CO_2, and not other GHGs, the EPA cannot rely on the analysis and conclusions in the 2009 Endangerment Finding because it concerned a mix of six GHGs: carbon dioxide and five others. These commenters assert that as a prerequisite for regulating CO_2 emissions alone, the EPA must make an endangerment finding for CO_2 alone. Because the present proposal also limits emissions of only CO_2, and not the other GHGs, we expect that the same issue may arise with respect to this proposal. Commenters' assertion is incorrect for two reasons. First, as discussed above, the EPA does not need to make an endangerment finding with respect to a particular pollutant to set standards for that pollutant under section 111(b)(1)(B). Second, the EPA may reasonably rely on the analysis and conclusions in the 2009 Endangerment Finding on GHGs even when regulating only CO_2. With respect to this proposed rulemaking, the air pollution at issue here is the mix of six GHGs. It is that air pollution that has caused the various impacts on health and welfare that formed the basis for the Endangerment Finding. The CO_2 emissions from EGUs are a major component of that air pollution. As we noted in the 2009 Endangerment Finding, CO_2 is the ''dominant anthropogenic greenhouse gas.'' [105] The fact that we are not regulating the other five GHGs in this rulemaking does not mean that we are required to identify the air pollution as CO_2 alone rather than the mix of six GHGs. This is consistent with the EPA's past actions. In the 2010 Light Duty Vehicle Rule for which the Endangerment Finding served as the predicate, the EPA regulated only four of the GHGs, not all six.[106]

Further, the fact that affected EGUs emit almost one-third of all U.S. GHGs and comprise by far the largest stationary source category of GHG emissions, along with the fact that the CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year, provide a rational basis for regulating CO_2 emissions from affected EGUs.[107] This is consistent with previous EPA actions that have been upheld by the D.C. Circuit. In the *National Lime Association* v. *EPA* case, noted above, the Court upheld the EPA's regulation of lime plants on grounds that they were one of the largest—although not within the largest 10 percent—emitting industries of particulates. The Court stated,

> EPA . . . focused . . . on the sheer quantity of dust generated by lime plants. *42 Fed. Reg. 22507* (''A study performed for EPA in 1975 by the Research Corporation of New England ranked the lime industry twenty-fifth on a list of 112 stationary sources categories which are emitters of particulate matter''); SSEIS 8–2 (''In a study performed for EPA by Argonne National Laboratory in 1975, the lime industry ranked seventh on a list of the 56 largest particulate source categories in the U.S.'').[108]

In the *National Asphalt Pavement Ass'n* v. *Train* case, noted above, the Court upheld the EPA's determination that the asphalt industry contributed significantly to the air pollution based on ''the number of existing plants, the expected rate of growth in the number of plants, the rate of uncontrolled emissions, and the level of emissions currently tolerated.'' [109]

F. Alternative Findings of Endangerment and Significant Contribution

Even if CAA section 111 is interpreted to require that the EPA make endangerment and cause-or-contribute significantly findings as prerequisites for today's rulemaking, then our rational

[101] 627 F.2d 416 (D.C. Cir. 1980).

[102] *Id.* at 431–32 n.48.

[103] *539 F.2d 775 (D.C. Cir. 1976).*

[104] *Id.* at 784.

[105] 74 FR 66496, 66519 (Dec. 15, 2009).

[106] 75 FR 25324, 25396–97 (May 7, 2010).

[107] Commenters on the original proposal stated that new solid-fuel fired power plants made no contribution to air pollution because EPA's modeling projected no new construction of those types of plants. However, CAA section 111(b)(1)(A) is clear by its terms that the source category listing that is the prerequisite to regulation is based on the contribution of the ''category'' to air pollution, and therefore is not based on the contribution of only new sources in the category. The same reasoning applies to the rational basis determination.

[108] 627 F.2d at 432, n. 48.

[109] 539 F.2d at 784–85.

basis, as described, should be considered to constitute those findings.

As noted above, the EPA's rational basis for regulating under section 111 GHGs is based primarily on the analysis and conclusions in the EPA's 2009 Endangerment Finding and 2010 denial of petitions to reconsider that Finding, coupled with the 2010, 2011, and 2012 assessments from the IPCC and NRC that describe scientific developments since those EPA actions. In addition, as noted above, we would review comments presenting other scientific information to determine whether that information has any meaningful impact on our primary basis.

This rational basis approach is substantially similar to the approach the EPA took in the 2009 Endangerment Finding and the 2010 denial of petitions to reconsider. As noted, the D.C. Circuit upheld that approach in the *CRR* case. Accordingly, that approach would support an endangerment finding for this rulemaking.

By the same token, if the EPA were required to make a cause-or-contribute-significantly finding for CO_2 emissions from the fossil fuel-fired EGUs, as a prerequisite to regulating such emissions under CAA section 111, the same facts that support our rational basis determination would support such a finding. In particular, as noted, fossil fuel-fired EGUs emit almost one-third of all U.S. GHG emissions, and constitute by far the largest single stationary source category of GHG emissions; and the CO_2 emissions from even a single new coal-fired power plant may amount to millions of tons each year. It should be noted that at present, it is not necessary for the EPA to decide whether it must identify a specific threshold for the amount of emissions from a source category that constitutes a significant contribution. Under any reasonable threshold or definition, the emissions from EGUs are a significant contribution.[110]

G. Comments on the State of the Science of Climate Change

The EPA received a number of comments in response to the original proposed NSPS rule addressing the scientific underpinnings of the EPA's 2009 Endangerment Finding and, in essence, the scientific justification for this rule. Because this action is not a final action, we are not required to respond to those comments. Even so, we have carefully reviewed all of those comments, and we do provide some responses in this action. It is important to place these comments in the context of the voluminous record on this subject that has been compiled over the last few years. This includes: (1) The process by which the Administrator reached the 2009 finding that GHGs are reasonably anticipated to endanger the public health and welfare of current and future generations; (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 D.C. Circuit (D.C. Circuit) in 2012 to uphold the Endangerment Finding and the Reconsideration Denial.

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 human 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. In brief, these assessments addressed the scientific issues that the EPA was required to examine, were comprehensive in their coverage of the GHG and climate change problem, and underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of U.S. government review and acceptance, in which the EPA took part. The EPA received thousands of comments on the proposed Endangerment Finding and responded to them in depth in an 11-volume RTC document. While the EPA gave careful consideration to *all* of the scientific and technical information received, it placed less weight on the much smaller number of individual studies that were not considered or reflected in the major assessments—often these studies were published after the submission deadline for those larger assessments. Primary reliance on the major scientific assessments provided the EPA greater assurance that it was basing its judgment on the best available, well-vetted science that reflected the consensus of the climate science community, rather than selecting the studies it would rely on. Nonetheless, the EPA reviewed individual studies not incorporated in the assessment literature to see if they would lead the EPA to change its interpretation of, or place less weight on, the major findings reflected in the assessment reports. From its review of individual studies submitted by commenters, the EPA concluded that these studies did not change the various conclusions or judgments the EPA would draw based on the more comprehensive assessment reports. The major findings of the USGCRP, IPCC, and NRC assessments supported the EPA's determination that GHGs threaten the public health and welfare of current and future generations. The EPA demonstrated this scientific support at length in the Endangerment Finding itself, in its Technical Support Document (which summarized the findings of USGCRP, IPCC and NRC), and in its RTC document.

The EPA then reviewed ten administrative petitions for reconsideration of the Endangerment Finding in 2010. The Administrator denied those petitions in the ''Reconsideration Denial'' on the basis that the Petitioners failed to provide substantial support for the argument that the Endangerment Finding should be revised and therefore their objections were not of ''central relevance'' to the Finding.[111] The EPA prepared an accompanying 3-volume RTP document to provide additional information, often more technical in nature, in response to the arguments, claims, and assertions by the petitioners to reconsider the Endangerment Finding.

The 2009 Endangerment Finding and the 2010 Reconsideration Denial were challenged in a lawsuit, and on June 26, 2012, the D.C. Circuit upheld them, ruling that they were neither arbitrary nor capricious, were consistent with *Massachusetts* v. *EPA,*[112] and were adequately supported by the administrative record.[113] The Court found that the EPA had based its decision on ''substantial scientific evidence,''[114] and noted that the EPA's reliance on assessments was consistent with the methods decision-makers often use to make a science-based judgment.[115] The Court also found that the Petitioners had ''not provided substantial support for their argument that the Endangerment Finding should be revised.''[116] Moreover, the Court assessed the EPA's reliance on the major scientific assessment reports that were

[110] Indeed, it is literally true that if fossil-fuel fired EGUs cannot be found to contribute significantly to GHG air pollution, then there is no source category in the U.S. that does contribute significantly to GHG air pollution, a result that would defeat the purposes of CAA section 111.

[111] ''EPA's Denial of the Petitions To Reconsider the Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act'' (''Reconsideration Denial''), 75 FR 49556, 58 (Aug. 13, 2010).

[112] *Massachusetts* v. *EPA,* 549 U.S. 497.

[113] *CRR,* 684 F.3d at 102.

[114] Id at 121.

[115] Id at 120.

[116] Id at 125.

conducted by USGCRP, IPCC, and NRC, and subjected to rigorous expert and government review, and found that—

> EPA evaluated the processes used to develop the various assessment reports, reviewed their contents, and considered the depth of the scientific consensus the reports represented. Based on these evaluations, the EPA determined the assessments represented the best source material to use in deciding whether GHG emissions may be reasonably anticipated to endanger public health or welfare.[117]

As the Court stated,

> It makes no difference that much of the scientific evidence in large part consisted of 'syntheses' of individual studies and research. Even individual studies and research papers often synthesize past work in an area and then build upon it. This is how science works. The EPA is not required to re-prove the existence of the atom every time it approaches a scientific question.[118]

It is within the context of this extensive record, and recent affirmation of the Endangerment Finding by the Court, that the EPA has considered all of the submitted science-related comments and reports for the April 2012 proposed rule, and will consider any further comments in response to today's proposed rule. As we did in the original Endangerment Finding, the EPA is giving careful consideration to all of the scientific and technical information in the record. However, the major peer-reviewed scientific assessments continue to provide the primary scientific and technical basis upon which the Administrator's judgment relies regarding the threat to public health and welfare posed by GHGs.

Commenters on the April 2012 proposed rule submitted two major peer-reviewed scientific assessments that were released since the administrative record concerning the Endangerment Finding was closed after the EPA's 2010 Reconsideration Denial: the IPCC Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation (2012) (SREX) and the NRC Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia (2011) (Climate Stabilization Targets). The EPA has reviewed these assessments and they are briefly characterized here:

SREX. The IPCC SREX assessment states that, ''A changing climate leads to changes in the frequency, intensity, spatial extent, duration, and timing of extreme weather and climate events, and can result in unprecedented extreme weather and climate events.'' The SREX documents observational evidence of changes in some of the weather and climate extremes that have occurred globally since 1950. The SREX assessment provides evidence regarding the attribution of some of these changes to elevated concentrations of GHGs, including warming of extreme daily temperatures, intensification of extreme precipitation events, and rising extreme coastal high water due to increases in sea level. The assessment notes that further increases in some extreme weather and climate events are projected over the 21st century. The assessment also concludes that, combined with increasing vulnerability and exposure of populations and assets, changes in extreme weather and climate events have consequences for disaster risk, with particular impacts on the water, agriculture and food security, and health sectors.

Climate Stabilization Targets. The NRC Climate Stabilization Targets assessment states 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.'' The assessment addresses the fact that emissions of carbon dioxide will alter the composition of the atmosphere, and therefore the climate, for thousands of years and attempts to quantify the implications of stabilizing GHG concentrations at different levels. The report also estimates a number of specific climate change impacts, finding warming could lead to increases in heavy rainfall and decreases in crop yields and Arctic sea ice extent, along with other important changes in precipitation and stream flow. For an increase in global average temperature of 1 to 2 °C above pre-industrial levels, the assessment found that the area burnt by wildfires in western North America will likely more than double and coral bleaching and erosion will increase due both to warming and ocean acidification; an increase of 3 °C will lead to a sea level rise of 0.5 to 1.0 meters by 2100; and with an increase of 4 °C, the average summer in the United States would be as warm as the warmest summers of the past century. The assessment notes that although many important aspects of climate change are difficult to quantify, the risk of adverse impacts is likely to increase with increasing temperature, and the risk of dangerous surprises can be expected to increase with the duration and magnitude of the warming.

A number of other National Academy assessments regarding climate have also been released recently. The EPA has reviewed these assessments, and finds that the improved understanding of the climate system resulting from the two assessments described above and the National Academy assessments strengthens the case that GHGs are endangering public health and welfare. Perhaps the most dramatic change relative to the prior assessments concern sea level rise. The previous 2007 IPCC AR4 assessment projected a rise in global sea level of between 7 and 23 inches by the end of the century relative to 1990 (with an acknowledgment that inclusion of ice sheet processes that were poorly understood would likely increase those projections). Three new NRC assessments have provided estimates of projected sea level rise that are much larger, in some cases more than twice as large as the previous IPCC estimates. Climate Stabilization Targets; National Security Implications for U.S. Naval Forces (2011); Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future (2012). While the three NRC assessments continue to recognize and characterize the uncertainty inherent in accounting for ice sheet processes, these revised estimates strongly support and strengthen the existing finding that GHGs are reasonably anticipated to endanger human health and welfare. Other key findings of the recent assessments are described briefly below:

The *Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future* (2012) assessment notes that observations have shown that sea level rise on the West Coast has risen south of Cape Mendocino over the past century but dropped north of that point during that time due to tectonic uplift and other factors in Oregon and Washington. However, the assessment projects a global sea level rise of 1.6 to 4.6 feet by 2100, which is sufficient to lead to rising relative sea level even in the northern states. The *National Security Implications of Climate Change for U.S. Naval Forces* also considers potential impacts of sea level rise, using a range of 1.3 to 6.6 feet by 2100. This assessment also suggests preparing for increased needs for humanitarian aid, responses to climate change in geopolitical hotspots including possible mass migrations, and addressing changing security needs in the Arctic as sea ice retreats. The *Climate and Social Stress: Implications for Security Analysis* (2012) assessment found that it

[117] Id at 120.

[118] Id at 120.

would be ''prudent for security analysts to expect climate surprises in the coming decade . . . and for them to become progressively more serious and more frequent thereafter[.]'' *Understanding Earth's Deep Past: Lessons for Our Climate Future* (2011) examines the period of Earth's history prior to the formation of the Antarctic and Greenland Ice Sheets because CO_2 concentrations by the end of the century will have exceeded levels seen in the 30 million years since that time. The assessment discusses the possibility that analogous paleoclimate states might suggest higher climate sensitivity, less well regulated tropical surface temperatures, higher sea level rise, more anoxic oceans, and more potential for non-linear events such as the Paleo-Eocene Thermal Maximum than previously estimated. The assessment notes that three or four out of the five major coral reef crises of the past 500 million years were probably driven by acidification and warming caused by GHG increases similar to the changes expected over the next hundred years. The assessment states 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.'' Similarly, the *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean* (2010) assessment found that ''[t]he chemistry of the ocean is changing at an unprecedented rate and magnitude due to anthropogenic carbon dioxide emissions; the rate of change exceeds any known to have occurred for at least the past hundreds of thousands of years.'' The assessment notes that the full range of consequences is still unknown, but the risks ''threaten coral reefs, fisheries, protected species, and other natural resources of value to society.''

Several commenters on the April 2012 proposed rule argue that the Endangerment Finding should be reconsidered or overturned based on those commenters' reviews of specific climate science literature, particularly newer publications that have appeared since the EPA's 2010 Denial of Petitions. Some commenters have presented their own compilations of individual studies as support for their assertions that climate change will have beneficial effects in many cases and that climate impacts will not be as severe or adverse as the EPA and assessments like the USGCRP (2009) report have stated. These commenters conclude that U.S. society will continue to easily adapt to climate change and that climate change therefore does not pose a threat to human health and welfare.

The EPA has reviewed the information submitted and finds that, the fundamental issues raised in the comments that critique the scientific justification for the rule have been addressed by the EPA's 11-volume response to comments for the 2009 Endangerment Finding, the EPA's responses to all issues raised by Petitioners in the Reconsideration Denial, or the D.C. Circuit in its 2012 decision to uphold the EPA's 2009 Endangerment Finding. These comments do not change the various conclusions or judgments that the EPA would draw based on the assessment reports relied upon in the recent 2009 Finding.

These comments often highlight uncertainty regarding climate science as an argument for reconsideration. However, uncertainty was explicitly recognized in the 2009 Endangerment Finding: ''The Administrator acknowledges that some aspects of climate change science and the projected impacts are more certain than others'',[119] and the decision to find endangerment was made with full recognition of the uncertainty involved. In addition, the D.C. Circuit Court decision noted that, ''the existence of some uncertainty does not, without more, warrant invalidation of an endangerment finding.'' [120] In short, these recent publications submitted by commenters, and any new issues that are extracted from them, do not undermine either the significant body of scientific evidence that has accumulated over the years or the conclusions presented in the substantial peer-reviewed assessments of the USGCRP, NRC, and IPCC.

Regarding the contentions that the U.S. will adapt to climate change impacts and that therefore climate change impacts pose no threat, the EPA stated in the 2009 Endangerment Finding,

> Risk reduction through adaptation and GHG mitigation measures is of course a strong focal area of scientists and policy makers, including the EPA; however, the EPA considers adaptation and mitigation to be potential *responses* to endangerment, and as such has determined that they are outside the scope of the endangerment analysis.[121]

The D.C. Circuit upheld this position, ruling that ''These contentions [that the U.S. can adapt] are foreclosed by the language of the statute and the Supreme Court's decision in *Massachusetts* v. *EPA''* because ''predicting society's adaptive response to the dangers or harms caused by climate change'' does not inform the ''scientific judgment'' that the EPA is required to take regarding Endangerment.[122]

Some commenters raise issues regarding the EPA Inspector General's report, *Procedural Review of EPA's Greenhouse Gases Endangerment Finding Data Quality Processes (2011).* These commenters mischaracterize the report's scope and conclusions and, thus, vastly overstate the significance of the Inspector General's procedural recommendations. Ultimately, nothing in the Inspector General report questions the validity of the EPA's Endangerment Finding because that report did not evaluate the scientific basis of the Endangerment Finding. Rather, the Inspector General offers recommendations for clarifying and standardizing internal procedures for documenting data quality and peer review processes when referencing existing peer reviewed science in the EPA actions. Unrelated to the Endangerment Finding and its validation by the Court, the EPA has made progress towards implementing the recommendations by the Inspector General.

One commenter submitted a number of emails from the period 1999 to 2009 that were obtained from a University of East Anglia server in 2009 and publicly released in 2011. After reviewing these emails, the EPA finds that they raise no issues that were not previously raised by Petitioners in regard to an earlier group of emails from the same incident, released in 2009. The commenter makes unsubstantiated assumptions and subjective assertions regarding what the emails purport to show about the state of climate change science; this provides inadequate evidence to challenge the voluminous and well documented body of science that is the technical foundation of the Administrator's Endangerment Finding.

A number of comments were also submitted in support of the Endangerment Finding and/or providing further evidence that climate change is a threat to human health and welfare. A number of individual studies were submitted and a number of observed or projected climate changes of local importance or concern to commenters were documented. Again, the EPA places lesser weight on individual studies than on the major scientific assessments. Local observed changes can be of great concern to individuals

[119] 74 FR 66524.

[120] *CRR,* 684 F.3d at 121.

[121] 74 FR 66512 (emphasis added).

[122] 984 F.3d at 117.

and communities but must be assessed in the context of the broader science, as it is more difficult to draw robust conclusions regarding climate change over short time scales and in small geographic regions.

V. Rationale for Applicability Requirements

A. Applicability Requirements—Original Proposal and Comments

The original proposal was designed to apply to new intermediate and base load EGUs, specifically, (1) fossil fuel-fired utility boilers and IGCC EGUs subject to subpart Da for criteria pollutant emissions, and (2) natural gas combined cycle EGUs subject to subpart KKKK for criteria pollutant emissions. The original proposal explicitly did not apply to simple cycle turbines because we concluded that they were operated infrequently and therefore only contributed small amounts to total GHG emissions. (For convenience, we occasionally refer to this explicit statement that the original proposed NSPS did not apply to a type of source as an exclusion.)

We received comments that supported the simple cycle exclusion and others that opposed it. Commenters in support stated that a new simple cycle power plant serves a different purpose than a new combined cycle plant and that economics will drive the use of combined cycle facilities over simple cycle plants. They also stated that the original proposed standard is not achievable by, and therefore is not BSER for, simple cycle turbines. Commenters opposing the exclusion stated that it creates an opportunity to evade the standard and could thereby increase GHG emissions. According to these commenters, any applicability distinctions should be based on utilization and function rather than purpose or technology.

After considering these comments, we are proposing a different approach to the applicability provisions with respect to simple cycle turbines.

B. Applicability Requirements—Today's Proposal

In today's rulemaking, we propose that standards of performance apply to a facility if the facility supplies more than one-third of its potential electric output and more than 219,000 MWh net electric output to the grid per year. (We refer to a facility's sale of more than one-third of its potential electric output as the one-third sales criterion, and we refer to the amount of potential electric output supplied to a utility power distribution system, expressed in MWh, as the capacity factor.) This proposed definition does not explicitly exclude simple cycle combustion turbines, but as a practical matter, it would exclude most of them because the vast majority of simple cycle turbines sell less than one-third of their potential electric output. The few simple-cycle combustion turbines that sell more than one-third of their potential electric output to the grid would be subject to the proposed standards of performance. As explained below, we have concluded that at this level of output, there are less expensive and lower emitting technologies that could be constructed consistent with today's proposed standards. Although, as noted, today's proposal does not explicitly exclude simple cycle combustion turbines, we solicit comment on whether to provide an explicit exclusion.

We are proposing to apply the one-third sales criterion on a rolling three year basis instead of an annual basis for stationary combustion turbines for multiple reasons. First, extending the period to three 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 even though they may provide system capacity and, in fact, operate at high capacity factors during individual years with abnormally high electric demand. Second, only 0.2 percent of existing simple cycle turbines had a three-year average capacity factor of greater than one-third between 2000 and 2012. Therefore, as noted, from a practical standpoint, few new simple cycle turbines will be subjected to the standards of performance in this rulemaking.

The 2013 AEO cost and performance characteristics for new generation technologies include costs for advanced and conventional combined cycle facilities and advanced simple cycle turbines. According to the AEO 2013 values, advanced combined cycle facilities have a lower cost of electricity than advanced simple cycle turbine facilities above approximately a 20 percent capacity factor. Therefore, the use of a combined cycle technology would be BSER for higher capacity factor stationary combustion turbines. However, advanced combined cycle facilities do not have a lower cost of electricity than less capital intensive conventional combined cycle facilities until above approximately a 40 percent capacity factor. Between approximately 20 to 40 percent capacity factors, conventional combined cycle facilities offer the lowest cost of electricity, and below approximately 20 percent capacity factors advanced simple cycle turbines offer the lowest cost of electricity. A capacity factor exemption at 40 percent (i.e., sales of less than two-fifths of potential electric output per year) would allow conventional combined cycle facilities built with the intent to operate at relatively low capacity factors as an alternative technology to simple cycle turbines because neither would be subject to the NSPS requirements. Based on these cost considerations, we are specifically requesting comment on a range of 20 to 40 percent of potential electric output sales on a three-year basis for the capacity factor exemption. The 20 percent applicability limit is consistent with generating the lowest cost of electricity for advanced combined cycle turbines compared to advanced simple cycle turbines, and based on historical capacity factors would impact the operation of only approximately two percent of simple cycle turbines. The 40 percent applicability limit would be more consistent with the annual run hour limitations currently contained in many simple cycle operating permits.

We are also requesting comments on whether applicability for stationary combustion turbines should be defined on a single calendar year basis, similar to the current subpart Da applicability provisions for criteria pollutants, instead of a three-year basis. With a single year basis, we are considering an applicability level of up to 40 (instead of 33 and one-third) percent sales. Only 0.4 percent of existing simple cycle turbines had an annual capacity factor of greater than 40 percent between 2000 and 2012. Assuming the average hourly output of a simple cycle turbine is 80 percent of the maximum rated output, a simple cycle turbine could operate up to 4,400 hours annually before exceeding the capacity factor threshold. This is consistent with the operation hour limitation in many permits. Therefore, with this 40 percent sales criterion on a single-year basis, as a practical matter, it is anticipated that few new simple cycle turbines would be subject to the proposed standards of performance. Thus, we are specifically requesting comment on a range of one-third to two-fifths of potential electric output annual sales. The lower range would be consistent with how an EGU is currently defined in the EPA rules, and would mean that the proposed standards of performance would impact approximately one percent of new simple cycle turbines.

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 and could discourage the installation of more efficient facilities. For example, a 33 percent efficient 100 MW facility would have a heat input of 1,034 MMBtu/h and a 40 percent efficient 100 MW facility would have a heat input of 853 MMBtu/h.[123] The 33 percent efficient facility would become subject to the NSPS requirements when it sells more than one-third of its potential electric output, 880,000 MWh. The 40 percent efficient facility would become subject to the NSPS requirements when it sells more than 730,000 MWh.[124] This could potentially encourage the construction of less efficient facilities, since they could have a higher actual capacity factor than a more efficient unit, while still not being an EGU subject to a CO_2 standard. 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. The proposed definition would permit the 40 percent efficient facility to use the actual efficiency of the facility so that the electric sales applicability criteria would be 880,000 MWh and applicability would be determined the same as for the less efficient facility.

The April 2012 proposal would have applied to facilities that primarily burn non-fossil fuels but also co-fire a fossil fuel. We have concluded that it is not appropriate to subject these facilities to the standards in today's proposal. This is because these types of units more closely resemble the non-fossil fuel-fired boilers and stationary combustion turbines that are not covered by today's proposed rule, than they do the fossil fuel-fired boilers and stationary combustion turbines that are covered by this rule. This approach is similar to the approach used in the Mercury and Air Toxics Standards, another CAA regulatory effort focused on fossil fuel-fired power plants. Therefore, we are proposing to limit the applicability of the standard to facilities where the heat input is comprised of more than 10.0 percent fossil fuel on a three-year rolling average basis. To simplify determining applicability with the CO_2 standard, we also request comment on whether the applicability for facilities that co-fire non-fossil fuels should be made on an annual average basis, instead of a three-year rolling average basis.

In the original proposal, we requested comment on the applicability of the GHG NSPS to combined heat and power (CHP) facilities and if applicability should be changed from how it is currently determined in subpart Da. In today's action, 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. As noted above, we propose that the proposed CO_2 standard of performance apply to a facility that supplies more than one-third of its potential electricity output and more than 219,000 MWh ''net electric output'' to the grid per year. The current definition of net electric output for purposes of criteria pollutants is ''the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis.'' 40 CFR 60.41Da. Owners/operators of a CHP facility under common ownership as an adjacent facility using the thermal output from the CHP facility (i.e., the thermal host) can subtract out power purchased by the adjacent facility on an annual basis when determining applicability. However, third-party CHP developers would not be able to benefit from the ''minus purchased power on a calendar year basis'' provision in the definition of net electric output when determining applicability since the CHP facility and the thermal host(s) are not under common ownership. 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.

This proposal includes within the definition of a steam electric generating unit, IGCC, and stationary combustion turbine that are 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. Including integrated equipment avoids circumvention of the requirements by having a boiler not subject to the standard supplying useful energy input (e.g., an industrial boiler supplying steam for amine regeneration in a CCS system) without accounting for the GHG emissions when determining compliance with the NSPS. In addition, the proposed definition would provide additional compliance flexibility similar to when the HRSG was included in the combustion turbine NSPS by recognizing the environmental benefit of integrated equipment that lowers the overall emissions rate of the affected facility. Even without this specific language, the original 1979 steam electric generating unit definition in subpart Da allows the use of solar thermal equipment for feedwater heating as an approach to integrating non-emitting generation to reduce environmental impact and lower the overall emissions rate. The current definition expands the flexibility to include combustion turbines, fuel cells, or other combustion technology for reheating or preheating boiler feedwater, preheating combustion air, producing steam for use in the steam turbine or to power the boiler feedpumps, or using the exhaust directly in the boiler to generate steam. This in theory could lower generation costs as well as lower the GHG emissions rate for an EGU.

We solicit comment on various issues concerning, and different approaches to, the applicability requirements for steam generating units and combustion turbines. In particular, we recognize that several of the requirements proposed today are based on the source's operations. These include, for both steam generating units and combustion turbines, the requirement that the source supply more than one-third of its potential electric output and more than 219,000 MWh net-electric output to the grid for sale on an annual or tri-annual basis (the one-third and 219,000 MWh sales requirement), as well as the requirement that the source burn fossil fuel for more than 10 percent of the heat input during three years; and for

[123] (100 MW)*(3.412 MMBtu/h/1 MWh)*(1/0.33) = 1,034 MMBtu/h. (100 MW)*(3.412 MMBtu/h/1 MWh)*(1/0.40) = 853 MMBtu/h.

[124] (1,034 MMBtu/h)*(1 MWh/3.412MMBtu/h)*(1/3)*(8,760h/yr) = 880,000 MWh. (853 MMBtu/h)*(1 MWh/3.412MMBtu/h)*(1/3)*(8,760h/yr) = 730,000 MWh.

combustion turbines, the additional requirement that the source combust over 90 percent natural gas on a heat input basis over three years.

We solicit comment on whether these requirements raise implementation issues because they are based on source operation after construction has occurred. We also solicit comment on whether, to avoid any such implementation issues, these requirements should be recast to be based on the source's purpose at the time of construction. For example, should we recast the 10% percent requirement so that it would be met if the source was constructed for the purpose of burning fossil fuel for more than 10 percent of its heat input over any three-year period?

In addition, we solicit comment on whether we should include these requirements not as applicability requirements for whether the source is subject to the standard of performance, but rather as criteria for which part of the standard of performance the source is subject to. Under this approach, at least for combustion turbines, the EPA would promulgate applicability requirements or a definition of utility unit designed to assure that combustion turbine utility units—but not combustion turbine industrial units or other types of non-utility units—would be subject to the standard of performance. For example, under this approach, all combustion turbine units that meet such applicability requirements or definition of utility units and that have a design heat input to the turbine engine greater than 250 MMBtu/h, would be subject to the standard of performance for CO_2 emissions. That standard would be: (i) during periods when certain conditions (noted below) are met, 1,000 or 1,100 lb CO_2/MWh (depending on whether the unit has a design heat input to the turbine engine of greater than 850 MMBtu/h); and (ii) during periods when one or more of those conditions is not met, no emission limit (that is, the unit could emit at an uncontrolled level). In the latter case, although the unit would not be subject to an emission limit, it would remain subject to the standard of performance, and therefore would be subject to any monitoring, reporting, and recordkeeping requirements. The conditions could include, during any 3-year period on a rolling average basis, combusting over 10% fossil fuel on a heat input basis, combusting over 90% natural gas on a heat input basis, and selling more than one-third of potential electric output and more than 219,000 MWh net-electric output to the grid.

Under this approach, as noted, in order to be consistent with today's proposal to apply the standard of performance for CO_2 emissions to only utility units—and not to industrial or other non-utility units—we would need to include other applicability requirements or definitional provisions that would explicitly limit the standard to utility units.

We solicit comment on all aspects of this approach, including the extent to which it would achieve the policy objectives of assuring that a simple cycle turbine and a combined cycle turbine are subject to the same standard if they sell more than one-third of their capacity and more than 219,000 KWh net electric output to the grid, and are subject to the same standard if they sell less than those amounts to the grid. We also solicit comment on how to implement the three-year requirements described above during the period within three years after an affected EGU begins operations. For example, under the approach where operational criteria that entail a three-year compliance period are used to determine to which standard of performance the facility is subject, the owner or operator and permitting authority would not know for certain what standard applies to the facility until three years after initial startup. For this scenario, we request comment on how to implement the three year operational requirements and what documentation should be collected and reported to the EPA during the period up to the end of the third year after a source begins operation.

C. Certain Projects Under Development

This proposal does not apply to the proposed Wolverine EGU project in Rogers City, Michigan. Based on current information, the Wolverine project appears to be the only fossil fuel-fired boiler or IGCC EGU project presently under development that may be capable of ''commencing construction'' for NSPS purposes [125] in the very near future and, as currently designed, could not meet the 1,100 lb CO_2/MWh standard proposed for other new fossil fuel-fired boiler and IGCC EGUs. The EPA has not formulated a view as to the project's status in the development process or as to whether the proposed 1,100 lb CO_2/MWh standard or some other CO_2 standard of performance would be representative of BSER for this project, and invites comment on these questions.[126] At the time of finalization of this proposal, if the Wolverine project remains under development and has not either commenced construction or been canceled, we anticipate proposing that the project either be made subject to the 1,100 lb CO_2/MWh standard or be assigned to a subcategory with an alternate CO_2 standard. Further discussion is provided in the technical support document in the docket entitled ''Fossil Fuel-Fired Boiler and IGCC EGU Projects under Development: Status and Approach.''

There are two other fossil fuel-fired boiler or IGCC EGU projects without CCS—the Washington County project in Georgia and the Holcomb project in Kansas—that appear to remain under development but whose developers have recently represented that the projects have commenced construction for NSPS purposes. Based solely on the developers' representations, the projects would be existing sources, and thus not subject to this proposal. However, neither developer has sought a formal EPA determination of NSPS applicability; and, if upon review it was determined that the projects have not commenced constructions, the projects should be situated similarly to the Wolverine project. Accordingly, if it is determined in the future that either of these projects has not commenced construction as of the date of this proposal, then that project will be addressed in the same manner as the Wolverine project.[127] Further discussion

[125] The NSPS regulations include definitions of ''commenced'' and ''construction''. *See* 40 CFR 60.2.

[126] The EPA's lack of view regarding the appropriate CO_2 standard is closely related to the existence of conflicting information on where the project stands in the development process. The developer has claimed that the project was delayed by issues related to the standards of performance for hazardous air pollutants promulgated in December 2011, 77 FR 9304 (Feb. 16, 2012) (Mercury and Air Toxics Standards, or MATS). Specifically, the developer cited a perceived inability to obtain guarantees from pollution control equipment vendors that the plant would achieve the MATS standards. *See* Jim Dulzo, *As Coal Plant Teeters, Groups Mount Legal Attack,* Michigan Land Use Institute blog, Feb. 13, 2012, *http://www.mlui.org/energy/news-views/news-views-articles/as-coal-plant-teeters-groups-mount-legal-attack.html.* While some of the MATS new-unit standards were revised upon reconsideration in March 2013, 78 FR 24073 (Apr. 24, 2013), the developer's claims raise the possibility that the EPA's own actions may have delayed the project and contributed to the present uncertainty as to the project's development status.

[127] In this event, there will not be any proposed standard ''which will be applicable to such source'' within the meaning of CAA section 111(a)(2), and to the extent that this proposal did, until the time of the construction commencement determination, apply to that project, this proposal will be considered automatically to be withdrawn as it applies to that project as of the time of that determination. The purpose of this automatic withdrawal is to ensure that the project is placed on the same footing as the Wolverine project as

Continued

is provided in the technical support document in the docket referenced above.[128]

We invite comment on all aspects of this approach for addressing the Wolverine project (and the Washington County and Holcomb projects, if applicable).[129]

VI. Legal Requirements for Establishing Emission Standards

A. Overview

In this section, we describe the principal legal requirement for the standards of performance under CAA section 111 that we propose in this rulemaking, which is that the standards must consist of emission limits that are based on the ''best system of emission reduction . . . adequately demonstrated,'' taking into account cost and other factors (BSER). In this manner, CAA section 111 provides that the EPA's central task is to identify the BSER. The D.C. Circuit has handed down case law, which we review in detail, that interprets this CAA provision, including its component elements. The Court's interpretation indicates the technical, economic, and energy-related factors that are relevant for determining the BSER, and provides the framework for analyzing those factors.

According to the D.C. Circuit, EPA determines the best demonstrated system based on the following key considerations, among others:

- The system of emission reduction must be technically feasible.
- EPA must consider the amount of emissions reductions that the system would generate.
- The costs of the system must be reasonable. 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.
- EPA must also consider that CAA section 111 is designed to promote the development and implementation of technology.

Other considerations are also important, including that 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, 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.

B. CAA Requirements and Court Interpretation

1. Clean Air Act Requirements

The EPA's basis for proposing that partial capture CCS is the BSER for new fossil fuel-fired utility boilers and IGCC units, and that NGCC is the BSER for natural gas-fired stationary combustion turbines, is rooted in the provisions of CAA section 111 requirements, as interpreted by the United States Court of Appeals for the D.C. Circuit (''D.C. Circuit'' or ''Court''), which is the federal Court of Appeals with jurisdiction over the EPA's CAA rulemaking.

As the first step towards establishing standards of performance, the EPA ''shall publish . . . a list of categories of stationary sources . . . [that] cause[], or contribute[ ] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' section 111(b)(1)(A). Following that listing, the EPA ''shall publish proposed regulations, establishing federal standards of performance for new sources within such category'' and then ''promulgate . . . such standards'' within a year after proposal. section 111(b)(1)(B). The EPA ''may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards.'' section 111(b)(2). The term ''standard of performance'' is defined to ''mean[ ] 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.'' section 111(a)(1).

2. Court Interpretation

For present purposes, the key section 111 provisions are the definition of ''standard of performance,'' under CAA section 111(a)(1), and, in particular, the ''best system of emission reduction which (taking into account . . . cost . . . nonair quality health and environmental impact and energy requirements) . . . has been adequately demonstrated.'' The D.C. Circuit has reviewed rulemakings under section 111 on numerous occasions during the past 40 years, handing down decisions dated from 1973 to 2011,[130] through which the Court has developed a body of case law that interprets the term ''standard of performance.'' These interpretations are of central importance to the EPA's justification for the standards of performance in the present rulemaking.

At the outset, it should be noted that Congress first included the definition of ''standard of performance'' when enacting CAA section 111 in the 1970 Clean Air Act Amendments (CAAA), and then amended it in the 1977 CAAA, and then amended it again in the 1990 CAAA, generally repealing the amendments in the 1977 CAAA and, therefore, reverting to the version as it read after the 1970 CAAA. The legislative history for the 1970 and 1977 CAAAs explained various aspects of the definition as it read at those times. Moreover, the various decisions of the D.C. Circuit interpreted the definition that was applicable to the rulemakings before the Court. Notwithstanding the amendments to the definition, the D.C. Circuit's interpretations discussed below remain applicable to the current definition.[131]

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soon as possible. It is worth noting that nothing in this proposal binds the EPA to the position that the projects have ''commenced construction'' for NSPS purposes.

[128] In the April 2012 GHG NSPS proposal, the Wolverine, Washington County, and Holcomb projects were among a group of 15 projects distinguished from other EGU projects as ''potential transitional sources.'' This proposal does not continue that distinction. Except as described above for the Wolverine project, and possibly the Washington County and Holcomb projects, any former ''potential transitional source'' that commences construction after publication of this proposal (and meets any other applicability criteria) will be subject to the final CO_2 standards established in this rulemaking. Any former ''potential transitional source'' that commenced construction prior to publication of this proposal is an existing source not subject to the CO_2 standards established in this rulemaking, but instead subject to the CO_2 standards that are required to be established for existing sources pursuant to CAA section 111(d).

[129] The EPA intends that its treatment of the Wolverine project (and the Washington County and Holcomb projects, if applicable) be severable from its treatment of differently situated sources and considers that severability is logical because of the record-based differences between these sources and differently situated sources and because there is no interdependency in the EPA's treatment of the different types of sources. This statement concerning severability should not be construed to have implications for whether other components in this rulemaking are severable.

[130] *Portland Cement Ass'n* v. *Ruckelshaus*, 486 F.2d 375 (D.C. Cir. 1973); *Essex Chemical Corp.* v. *Ruckelshaus*, 486 F.2d 427, (D.C. Cir. 1973); *Portland Cement Ass'n* v. *EPA*, 665 F.3d 177 (D.C. Cir. 2011).

[131] In the 1970 CAAA, Congress defined ''standard of performance,'' under section 111(a)(1), 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) the Administrator determines has been adequately demonstrated.

In the 1977 CAAA, Congress revised the definition to distinguish among different types of sources, and to require that for fossil fuel-fired sources, the standard (i) be based on, in lieu of the ''best system of emission reduction . . . adequately

3. Overview of Interpretation

By its terms, the definition of ''standard of performance'' under CAA section 111(a)(1) provides that the emission limit that the EPA promulgates must be ''achievable'' and must be based on a system of emission reduction—generally, but not required to be always, a technological control—that the EPA determines to be the ''best system'' that is ''adequately demonstrated,'' ''taking into account . . . cost . . . nonair quality health and environmental impact and energy requirements.'' The D.C. Circuit has stated that in determining the ''best'' system, the EPA must also take into account ''the amount of air pollution'' [132] and ''technological innovation.''[133]

As discussed below, the D.C. Circuit has elaborated on the criteria and process for determining whether a standard is ''achievable,'' based on an ''adequately demonstrated'' technology or system. In addition, the Court has identified limits on the costs and other factors that are acceptable for the technology or system to qualify as the ''best.'' The Court has also held that the EPA may consider the costs and other factors on a regional or national level (e.g., the EPA may consider impacts on the national economy and the affected industry as a whole) and over time, and not just on a plant-specific level at the time of the rulemaking.[134] In addition, the Court has emphasized that the EPA has a great deal of discretion in weighing the various factors to determine the ''best system.'' [135] Moreover, the Court has stated that in considering the various factors and determining the ''best system,'' the EPA must be mindful of the purposes of section 111, and the Court has identified those purposes as ''not giv[ing] a competitive advantage to one State over another in attracting industry[,]''. . . ''reducing emissions as much as practicable[,]''. . . ''forc[ing] the installation of all the control technology that will ever be necessary on new plants at the time of construction[,]. . .'' and ''forc[ing] the development of improved technology.''[136] Finally, based on cases the D.C. Circuit has handed down under related provisions of the CAA and the EPA's regulatory precedent under section 111, the EPA may promulgate a standard of performance for a particular category of sources even if not every type of new source in the category would be able to achieve that standard.[137]

We next discuss in more detail each of these components of the interpretation of ''standard of performance.''

C. Technical Feasibility

The D.C. Circuit's first decision under section 111, *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973), concerned whether EPA's standard of performance for the cement industry met the requirement to be ''achievable,'' which, in turn, depended on whether the technology on which EPA based the standard was ''adequately demonstrated.'' [138] In this case, the Court interpreted these provisions to require that the technology must be technically feasible for the source category, and established criteria for determining technical feasibility.

The Court explained that a standard of performance is ''achievable'' if a technology can reasonably be projected to be available to new sources at the time they are constructed that will allow them to meet the standard. Specifically, the D.C. Circuit explained:

> Section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present, since it is addressed to standards for new plants. . . .—It is the ''achievability'' of the proposed standard that is in issue . . . .
>
> The Senate Report made clear that it did not intend that the technology ''must be in actual routine use somewhere.'' The essential question was rather whether the technology would be available for installation in new plants. . . . The Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on ''crystal ball'' inquiry.[139]

In subsequent cases, the D.C. Circuit has consistently reiterated this formulation of ''achievable.'' [140]

It should be noted that in another of the early cases, *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973), the D.C. Circuit upheld a standard of performance as ''achievable'' on the basis of test data showing that the tested plant emitted less than or at the standard on three occasions and emitted above the standard on 16 occasions, and that, on average, it emitted 15 percent above the standard on a total of 19 occasions.[141] The fact that the plant had achieved the standard on at least a few occasions, even though the plant had not done so on the great majority of occasions, ''adequately demonstrated'' that the standard was ''achievable.''

D. Factors To Consider in Determining the ''Best System''

1. Amount of Emissions Reductions

Although the definition of ''standard of performance'' does not by its terms identify the amount of emissions from the category of sources and the amount of emission reductions achieved as factors the EPA must consider in determining the ''best system of emission reduction,'' the D.C. Circuit has stated that the EPA must do so. *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981) (''we can think of no sensible interpretation of the statutory words ''best . . . system'' which would not incorporate the amount of air pollution as a relevant factor to be weighed when determining the optimal standard for controlling . . . emissions'').[142] This is consistent with the Court's statements in *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973) that it is necessary to ''[k]eep[ ] in mind Congress' intent that new plants be

demonstrated,'' the ''best technological system of continuous emission reduction . . . adequately demonstrated;'' and (ii) require a percentage reduction in emissions. In addition, in the 1977 CAAA, Congress expanded the parenthetical requirement that the Administrator consider the cost of achieving the reduction to also require the Administrator to consider ''any nonair quality health and environment impact and energy requirements.''

In the 1990 CAAA, Congress again revised the definition, this time repealing the requirements that the standard of performance be based on the best technological system and achieve a percentage reduction in emissions, and replacing those provisions with the terms used in the 1970 CAAA version of section 111(a)(1) that the standard of performance be based on the ''best system of emission reduction . . . adequately demonstrated.'' This 1990 CAAA version is the current definition, which is applicable at present. Even so, because parts of the definition as it read under the 1977 CAAA were retained in the 1990 CAAA, the explanation in the 1977 CAAA legislative history, and the interpretation in the case law, of those parts of the definition remain relevant to the definition as it reads today.

[132] *See Sierra Club* v. *Costle,* 657 F.2d 298, 326 (D.C. Cir. 1981).

[133] *See Sierra Club* v. *Costle,* 657 F.2d at 347.

[134] See *Sierra Club* v. *Costle,* 657 F.2d at 330.

[135] See *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999).

[136] *Sierra Club* v. *Costle,* 657 F.2d at 325 & n.83 (quoting 44 FR 33580, 33581/3–33582/1).

[137] *See, e.g., International Harvester Co.* v. *EPA,* 478 F.2d 615, 640 (D.C. Cir. 1973).

[138] 486 F.2d at 390.

[139] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (citations omitted).

[140] *See, e.g., National Asphalt Pavement Ass'n* v. *Train,* 539 F.2d 775, 785 (D.C. Cir. 1976); *Lignite Energy Council* v. *EPA,* 109 F.3d 930, 934 (D.C. Cir. 1999).

[141] *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d at 437 & n. 27.

[142] *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981) was governed by the 1977 CAAA version of the definition of ''standard of performance,'' which revised the phrase ''best system'' to read, ''best *technological* system.'' The 1990 CAAA deleted ''technological,'' and thereby returned the phrase to how it read under the 1970 CAAA. The *Sierra Club* v. *Costle*'s interpretation of this phrase to require consideration of the amount of air emissions remains valid for the phrase ''best system.''

controlled to the 'maximum practicable degree.' '' [143]

2. Costs

In several cases, the D.C. Circuit has elaborated on the cost factor that the EPA is required to consider under CAA section 111(a)(1), and has identified limits to how costly a control technology may be before it no longer qualifies as the ''best system of emission reduction . . . adequately demonstrated.'' As a related matter, although no D.C. Circuit case addresses how to account for revenue generated from the byproducts of pollution control, it is logical and a reasonable interpretation of the statute that any expected revenues from the sale of pollutants or pollution control byproducts associated with those controls may be considered when determining the overall costs of implementation of the control technology. Clearly, such a sale would offset regulatory costs and so must be included to accurately assess the costs of the standard.

a. Criteria for Costs

(i) Formulation

In *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d 427, 433 (D.C. Cir. 1973), the D.C. Circuit stated that to be ''adequately demonstrated,'' the system must be ''reasonably reliable, reasonably efficient, and . . . reasonably expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' The Court has reiterated this limit in subsequent case law, including *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999), in which it stated: ''EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.'' In *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975), the Court elaborated by explaining that the inquiry is whether the costs of the standard are ''greater than the industry could bear and survive.'' [144]

In *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981), the Court provided a substantially similar formulation of the cost standard when it held: ''EPA concluded that the Electric Utilities' forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.'' We believe that these various formulations of the cost standard—''exorbitant,'' ''greater than the industry could bear and survive,'' ''excessive,'' and ''unreasonable''—are synonymous; the D.C. Circuit has made no attempt to distinguish among them. For convenience, in this rulemaking, we will use reasonableness as the standard, so that a control technology may be considered the ''best system of emission reduction . . . adequately demonstrated'' if its costs are reasonable, but cannot be considered the best system if its costs are unreasonable.

(ii) Examples

In the case law under CAA section 111, the D.C. Circuit has never invalidated a standard of performance on grounds that it was too costly. In several cases, the Court upheld standards that entailed high costs. In *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d 375 (D.C. Cir. 1973), the Court considered a standard of performance that the EPA promulgated for particulate matter emissions from new and modified Portland cement plants. According to the Court, the cost for the control technologies that a new facility would need to install to meet the standard was about 12 percent of the capital investment for the total facility, and annual operating costs for the control equipment would be 5–7 percent of the total plant operating costs. The Court found that these costs ''could be passed on without substantially affecting competition'' because the demand for the product was not ''highly elastic with regard to price and would not be very sensitive to small price changes.'' The Court held that the EPA gave appropriate consideration to the ''economic costs to the industry.'' [145]

In *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), the D.C. Circuit upheld a standard of performance imposing costly controls on SO_2 emissions from coal-fired power plants. The Court noted:

> The importance of the challenged standards arises not only from the magnitude of the environmental and health interests involved, but also from the critical implications the new pollution controls have for the economy at the local and national levels.
>
> * * * * *
>
> Coal is the dominant fuel used for generating electricity in the United States. . . . In 1976 power plant emissions accounted for 64 percent of the total estimated sulfur dioxide emissions and 24 percent of the total estimated particulate matter emissions in the entire country.
>
> EPA's revised NSPS are designed to curtail these emissions. EPA predicts that the new standards would reduce national sulfur dioxide emissions from new plants by 50 percent and national particulate matter emissions by 70 percent by 1995. The cost of the new controls, however, is *substantial.* EPA estimates that utilities will have to spend *tens of billions of dollars* by 1995 on pollution control under the new NSPS. *Consumers will ultimately bear these costs, both directly in the form of residential utility bills, and indirectly in the form of higher consumer prices due to increased energy costs.*[146]

b. Revenue Enhancements

In determining the costs of pollution control technology, it is reasonable to take into account any revenues generated by the sale of any by-products of the control process. Many types of pollution control technology generate byproducts that must be disposed, and the costs of that disposal are considered part of the costs of the control technology. For example, CCS generates a stream of CO_2 that must be disposed of through sequestration.

In some instances, however, the by-products of pollution control have marketable value. In these cases, revenues from selling the by-products would defray the costs of pollution control. For example, in a recent rulemaking under the CAA regional haze program that entailed determining the ''best available retrofit technology'' (BART) for power plants, revenue from fly ash generated during boiler combustion and sold for use in concrete production factored into the State's selection of BART).[147]

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[143] *Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d at 437 & n. 27 (citing ''Summary of the Provisions of Conference Agreement on the Clean Air Amendments of 1970,'' 116 Cong. Rec. 42384, 42385 (1970)).

[144] The 1977 House Committee Report noted:

> In the [1970] Congress [*sic:* Congress's] view, it was only right that the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business.

1977 House Committee Report at 184. Similarly, the 1970 Senate Committee Report stated:

> The implicit consideration of economic factors in determining whether technology is ''available'' should not affect the usefulness of this section. The overriding purpose of this section would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach.

S. Comm. Rep. No. 91–1196 at 16.

[145] *Portland Cement Association* v. *Ruckelshaus,* 486 F.2d at 387–88.

[146] *Sierra Club* v. *Costle,* 657 F.2d at 313 (citations omitted) (emphasis added).

[147] Similarly, the EPA has taken into account the value of fuel savings in determining the costs of rules that limit emissions from motor vehicles, which limits manufacturers are expected to achieve by reducing the rates of fuel consumption by the vehicles. *See, e.g.,* 77 FR 62624, 62628–29; 62923–27; 62942–46 (October 15, 2012) (rulemaking setting GHG emissions standards for Light-Duty Vehicles for Model Years 2017–2025).

3. Expanded Use and Development of Technology

In *Sierra Club* v. *Costle,* the Court made clear that technological innovation was grounded in the terms of section 111 itself, and therefore should be considered one of the factors to be considered in determining the ''best system of emission reduction:''

Our interpretation of section 111(a) is that the mandated balancing of cost, energy, and nonair quality health and environmental factors embraces consideration of technological innovation as part of that balance. The statutory factors which EPA must weigh are broadly defined and include within their ambit subfactors such as technological innovation.[148]

The Court's interpretation finds firm grounding in the legislative history. For example, the 1970 Senate Committee Report stated:

Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources, since more effective emission control will provide greater latitude in the selection of sites for new facilities.[149]

Similarly, the 1977 Senate Committee Report stated:

In passing the Clean Air Amendments of 1970, the Congress for the first time imposed a requirement for specified levels of control technology. The section 111 Standards of Performance for New Stationary Sources required the use of the ''best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated.'' This requirement sought to assure the use of available technology and to stimulate the development of new technology.[150]

The legislative history just quoted identifies three different ways that Congress designed section 111 to authorize standards of performance that promote technological improvement: (i) the development of technology that may be treated as the ''best system of emission reduction . . . adequately demonstrated;'' under section 111(a)(1)[151]; (ii) the expanded use of the best demonstrated technology;[152] and (iii) the development of emerging technology.[153]

E. Nationwide Component of Factors in Determining the ''Best System''

Another component of the D.C. Circuit's interpretations of section 111 is that the EPA may consider the various factors it is required to balance on a national or regional level and over time, and not only on a plant-specific level at the time of the rulemaking.[154] As the D.C. Circuit stated in *Sierra Club* v. *Costle:*

The language of [the definition of 'standard of performance' in] section 111 . . . gives EPA authority when determining the best . . . system to weigh cost, energy, and environmental impacts in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present.[155]

In that case, in upholding the EPA's variable standard for SO_2 emissions, the D.C. Circuit justified and elaborated on that interpretation of the definition of ''standard of performance'' and then went on to evaluate the EPA's justification for its rulemaking in light of that interpretation. It is useful to set out these parts of the Court's opinion at some length in order to make clear the scope of the factors and the nature of the balancing exercise that the Court held section 111(a)(1) authorizes the EPA to take.

The Court first recited the terms of the definition of ''standard of performance,'' as it read following the 1977 CAA Amendments:

The pertinent portion of section 111 reads:

A standard of performance shall reflect the degree of emission limitation . . . achievable through application of the best . . . system of . . . emission reduction which (taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[156]

The Court then stated that these terms could reasonably be read to authorize the EPA to establish the standard of performance based on environmental, economic, and energy considerations ''on the grand scale:''

Parsed, section 111 most reasonably seems to require that EPA identify the emission levels that are ''achievable'' with ''adequately demonstrated technology.'' After EPA makes this determination, it must exercise its discretion to choose an achievable emission level which represents the best balance of economic, environmental, and energy considerations. It follows that to exercise this discretion EPA must examine the effects of technology on the grand scale in order to decide which level of control is best. For example, an efficient water intensive technology capable of 95 percent removal efficiency might be ''best'' in the East where water is plentiful, but environmentally disastrous in the water-scarce West where a different technology, capable of only 80 percent reduction efficiency might be ''best.'' . . . The standard is, after all, a national standard with long-term effects.[157]

The Court then justified its ''reading of . . . section 111 as authorizing the EPA to balance long-term national and regional impacts of alternative standards'' on the 1977 CAAA legislative history:

The Conferees defined the best technology in terms of ''long-term growth,'' ''long-term cost savings,'' effects on the ''coal market,'' including prices and utilization of coal reserves, and ''incentives for improved technology.'' Indeed, the Reports from both Houses on the Senate and House bills illustrate very clearly that Congress itself was using a long-term lens with a broad focus on future costs, environmental and energy effects of different technological systems when it discussed section 111.[158]

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[148] *Sierra Club* v. *Costle,* 657 F.2d at 347.

[149] S. Rep. 91–1196 at 16 (1970). The technology-forcing nature of section 111 is consistent with the technology-forcing nature of the 1970 CAAA as a whole. The principal Senate author of the 1970 CAAA, Sen. Edmund Muskie (D–ME), during the Senate floor debate, described the overall requirements of the 1970 CAAA and then observed:

These five sets of requirements will be difficult to meet. But the committee is convinced that industry can make compliance with them possible or impossible. It is completely within their control. Industry has been presented with challenges in the past that seemed impossible to meet, but has been made possible.

116 Cong. Rec. 32902 (Sept. 21, 1970) (statement of Sen. Muskie).

[150] S. Rep. 95–127 at 17 (1977), cited in *Sierra Club* v. *Costle,* 657 F.2d at 346 n. 174. The 1977 CAAA legislative history is replete with other references to the technology forcing nature of section 111 or the CAAA as a whole. *See* ''1977 Clean Air Act Conference Report: Statement of Intent; Clarification of Select Provisions,'' 123 Cong. Rec. 27071 (1977) (quoted in *Sierra Club* v. *Costle,* 657 F.2d at 346 n. 174) (one of the enumerated purposes of section 111 was to ''create incentives for new technology''); 123 Cong. Reg. 16195 (May 24, 1977) (statement of Rep. Meads) (''The main purposes of the Clean Air Act Amendments of 1977 are as follows: … tenth, to promote the utilization of new technologies for pollution choice'').

[151] *See Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973) (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'').

[152] *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'').

[153] *See Sierra Club* v. *Costle,* 657 F.2d at 351 (upholding a standard of performance designed to promote the use of an emerging technology).

[154] Sierra Club v. Costle, 657 F.2d at 351.

[155] *Sierra Club* v. *Costle,* 657 F.2d at 330.

[156] *Sierra Club* v. *Costle,* 657 F.2d at 330. Note that the elipses in the quotation of the definition of ''standard of performance'' in the text indicate the omission of terms repealed by the 1990 CAAA. The Court's analysis of the meaning of this definition did not turn on those repealed terms, and as a result, the Court's analysis remains relevant for the current definition of ''standard of performance.''

[157] *Sierra Club* v. *Costle,* 657 F.2d at 330 (emphasis added). As noted, after the 1990 CAAA—which changed the term ''best *technological* system . . . of emission reduction . . . adequately demonstrated'' to ''best system . . . of emission reduction . . . adequately demonstrated''—the Court's discussion of ''adequately demonstrated technology'' should be considered to hold true for adequately demonstrated system of emission reduction.

[158] *Sierra Club* v. *Costle,* 657 F.2d at 331 (citations omitted) (citing legislative history).

The Court then examined the EPA's justification for the variable standard, and held that the justification was reasonable.[159] The Court quoted at length the EPA's discussion of how it ''justified the variable standard in terms of the policies of the Act,'' including balancing long-term national and regional impacts:

> The standard reflects a balance in environmental, economic, and energy consideration by being sufficiently stringent to bring about substantial reductions in SO_2 emissions (3 million tons in 1995) yet does so at reasonable costs without significant energy penalties. . . . By achieving a balanced coal demand within the utility sector and by promoting the development of less expensive SO_2 control technology, the final standard will expand environmentally acceptable energy supplies to existing power plants and industrial sources.
>
> By substantially reducing SO_2 emissions, the standard will enhance the potential for long term economic growth at both the national and regional levels.[160]

F. Chevron Framework

Above, we discuss how in *Sierra Club* v. *Costle* the D.C. Circuit interpreted the definition of ''standard of performance'' in CAA section 111(a)(1), among other things, to authorize the EPA to balance economic, environmental, or energy factors through a nationwide lens, and to encompass technology forcing. The D.C. Circuit handed down this decision in 1981, and therefore it did not employ the two-step framework for statutory construction in federal rulemaking that the U.S. Supreme Court mandated in 1984, in *Chevron U.S.A. Inc.* v. *NRDC,* 467 U.S. 837 (1984). However, the D.C. Circuit's interpretations are fully consistent with the *Chevron* framework.

In *Chevron,* the Supreme Court held that an agency must, at Step 1, determine whether Congress's intent as to the specific matter at issue is clear, and, if so, the agency must give effect to that intent. If congressional intent is not clear, then, at Step 2, the agency has discretion to fashion an interpretation that is a reasonable construction of the statute.[161]

As noted, under CAA section 111(a)(1), a standard of performance must be based on 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) . . . has been adequately demonstrated.'' The terms ''best system of emission reduction,'' ''cost,'' and ''energy requirements,'' on their face, can be interpreted to apply on a regionwide or nationwide basis, and are not limited to the individual source. Thus, this interpretation is supportable under *Chevron* step 1, but even if not, then the EPA considers the interpretation supportable under step 2 because it is reasonable and consistent with the purposes of the CAA. Similarly, the technology-development interpretation is supportable under *Chevron* step 1 because encouraging the utilization or development of improved technology is a logical consideration in determining the ''best system of emission reduction'' and, as noted, was clearly a focus of the legislative history. Even if that interpretation is not supportable under *Chevron* step 1, however, then the EPA considers the interpretation supportable under step 2 because it is reasonable and consistent with the purposes of the CAA.

G. Agency Discretion

The D.C. Circuit has made clear that the EPA has broad discretion in determining the appropriate standard of performance under the definition in CAA section 111(a)(1), quoted above. Specifically, in *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981), the Court explained that ''section 111(a) explicitly instructs the EPA to balance multiple concerns when promulgating a NSPS,'' [162] and emphasized that ''[t]he text gives the EPA broad discretion to weigh different factors in setting the standard.'' [163] In *Lignite Energy Council* v. *EPA,* 198 F.3d 930 (D.C. Cir. 1999), the Court reiterated:

> Because section 111 does not set forth the weight that should be assigned to each of these factors, we have granted the agency a great degree of discretion in balancing them. . . . EPA's choice [of the ''best system''] will be sustained unless the environmental or economic costs of using the technology are exorbitant. . . . EPA [has] considerable discretion under section 111.[164]

The important point is that Courts acknowledge that there are several factors to be considered and what is ''best'' depends on how much weight to give the factors. In promulgating certain standards of performance, EPA may give greater weight to particular factors than it may do so in promulgating other standards of performance. Thus, the determination of what is ''best'' is complex and necessarily requires an exercise of judgment. By analogy, the question of who is the ''best'' sprinter in the 100-meter dash primarily depends on only one criterion—speed—and therefore is relatively straightforward, while the question of who is the ''best'' baseball player depends on a more complex weighing of several criteria and therefore requires a greater exercise of judgment.

H. Lack of Requirement That Standard Be Able To Be Met by All Sources

Under CAA section 111, an emissions standard may meet the requirements of a ''standard of performance'' even if it cannot be met by every new source in the source category that would have constructed in the absence of that standard. As discussed below, this is clear in light of (i) the legislative history of CAA section 111, read in conjunction with the legislative history of the CAA as a whole; (ii) case law under analogous CAA provisions; and (iii) long-standing precedent in the EPA rulemakings under CAA section 111.

1. Legislative History

As noted, Congress, in enacting section 111 in the 1970 CAAA, intended that the EPA promulgate uniform, nationwide controls. Congress was explicit that this meant that large industrial sources, including electric generating power plants, would be required to implement controls meeting the requirements regardless of their location. According to the 1970 Senate Committee Report:

> Major new facilities such as electric generating plants, kraft pulp mills, petroleum refineries, steel mills, primary smelting plants, and various other commercial and industrial operations must be controlled to the maximum practicable degree regardless of their location and industrial operations * * *.[165]

Congress's purposes in designing a standard that called for uniform national controls were to prevent pollution havens—caused by some states seeking competitive advantage by limiting their pollution control requirements—and to assure that areas that had good air quality would be able to maintain good air quality even after new industrial sources located there, which, in turn, would allow more sources to locate there as well.[166]

At the same time, Congress recognized that in light of the attainment provisions of the CAAA of 1970, sources—particularly large industrial sources, again, including electric generating plants—may not be

[159] *Sierra Club* v. *Costle,* 657 F.2d at 337–39.

[160] *Sierra Club* v. *Costle,* 657 F.2d at 327–28 (quoting 44 FR 33583/3–33584/1).

[161] *Chevron U.S.A. Inc.* v. *NRDC,* 467 U.S. 837, 842–43 (1984).

[162] *Sierra Club* v. *Costle,* 657 F.2d at 319.

[163] *Sierra Club* v. *Costle,* 657 F.2d at 321.

[164] *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) (paragraphing revised for convenience).

[165] S. Rep. 91–1116 at 16 (1970). *See* 116 Cong. Rec. 42,384 (statement of Sen. Muskie) (summarizing the House-Senate Conference agreement).)

[166] *See* S. Rep. 91–1196 at 16 (1970).

able to construct new facilities anywhere in the country; that is, an area with air quality at or above the NAAQS limits might not have enough room in its airshed to accommodate these new facilities. The 1970 Senate Committee Report stated, ''[l]and use policies must be developed to prevent location of facilities which are not compatible with implementation of national standards.'' [167] Senator Muskie added:

> Land use planning and control should be used by State, local, and regional agencies as a method of minimizing air pollution. Large industries and power generating facilities should be located in places where their adverse effect on the air is minimal. There is a need for State or regional agencies to revise proposed power plant sites to assure that a number of environmental values, including air pollution, are considered.[168]

The 1970 CAAA legislative history includes other statements that also recognize that under the newly required air pollution control requirements, new sources may not be able to build anywhere in the country and, in fact, some existing sources might have to be shut down.[169]

Thus, in 1970, Congress designed section 111 to require uniform national controls for large industrial facilities, while recognizing that those facilities could not necessarily construct in every place in the country. Although at the time, Congress expected that the reason why some sources would not be able to locate in certain places was related to local air quality concerns, if the reason turns out to be related to the emission limits that the EPA promulgates under section 111, that should not be viewed as inconsistent with congressional intent for section 111. For example, if the EPA promulgates section 111 emission limits based on a particular type of technology, and for economic or technical reasons, sources are able to utilize that technology in only certain parts of the country and not other parts, that result should not be viewed as inconsistent with congressional intent for CAA section 111. Rather, that result is consistent with Congress's recognition that certain sources may be precluded from locating in certain areas.

2. Case Law Under Analogous CAA Provisions

Under analogous CAA provisions, the D.C. Circuit has recognized that the EPA may promulgate uniform standards that apply to new sources in a group or category of sources, even though some types of those new sources that would otherwise construct would no longer be able to construct because they could not meet the standard. One of these cases was *International Harvester Co.* v. *EPA,* 478 F.2d 615 (D.C. Cir. 1973). There, the EPA declined to exercise its discretion under the CAA mobile source provisions, as they read at that time (42 U.S.C. 1857f–1(b)(5)(D) (1970 CAAA)), to grant automakers a one-year extension to comply with exhaust standards. The EPA stated that the automakers had failed to meet their burden of establishing that controls were not available. The EPA based its decision on grounds that certain technology was available for the motor vehicles in question. The EPA dismissed the automakers' objections that this technology could not feasibly be installed in all models or engine types, and the EPA explained that the public's ''basic demand'' for automobiles could be met by the models and engine types that could feasibly install that technology. 478 F.2d at 626.

Although the Court remanded the EPA's decision not to grant the one-year extension, it agreed with the EPA on this point, stating:

> We are inclined to agree with the Administrator that as long as feasible technology permits the demand for new passenger automobiles to be generally met, the basic requirements of the Act would be satisfied, even though this might occasion fewer models and a more limited choice of engine types. The driving preferences of hot rodders are not to outweigh the goal of a clean environment.[170]

Similarly, in a 2007 decision under CAA section 112, *NRDC* v. *EPA,* 489 F.3d 1364, 1376 (D.C. Cir. 2007) the D.C. Circuit upheld the EPA's decision to apply the same hazardous air pollutant requirements to different types of plywood and composite wood products facilities—even though one of those types of facilities faced greater difficulties meeting the requirements than the other types of facilities—in part on the grounds that the facilities ''compet[ed] in the same markets.'' [171]

Thus, these decisions supported EPA's emissions requirements, even though certain types of sources could meet those requirements more readily than others, on grounds that the requirements would not impede the manufacture of products that would satisfy overall consumer demand. By the same token, the inability of some coal-fired sources to locate in certain areas would not create reliability problems or prevent the satisfaction of overall demand for electricity.

3. Section 111 Rulemaking Precedent

Through long-standing rulemaking precedent, the EPA has taken the position that section 111 authorizes a standard of performance for a source category that may not be feasible for all types of new sources in the category, as long as there are other types of sources in the category that can serve the same function and meet the standard. Specifically, in a 1976 rulemaking under section 111 covering primary copper, zinc, and lead smelters, the EPA established, as the standard of performance, a single standard for SO_2 emissions for new construction or modifications of reverberatory, flash, and electric smelting furnaces in primary copper smelters that process materials with low levels of volatile impurities. The EPA acknowledged that although for flash and electric smelting furnaces, the cost of the controls was ''reasonable,'' for reverberatory smelting furnaces, the cost of the standard was ''unreasonable in most cases.'' Even so, the EPA determined that this standard would not adversely affect new construction or modification of primary copper smelters processing materials containing low levels of volatile impurities because new construction could use flash and electric smelting furnaces, and existing sources could expand without increasing emissions.[172] The EPA explained:

> [T]he Agency believes that section 111 authorizes the promulgation of one standard applicable to all processes used by a class of sources, in order that the standard may reflect the maximum feasible control for that class. When the application of a standard to a given process would effectively ban the process, however, a separate standard must be prescribed for it unless some other process(es) is available to perform the function at reasonable cost. . . .
>
> The Administrator has determined that the flash copper smelting process is available and will perform the function of the reverberatory copper smelting process at reasonable cost. . . .[173]

VII. Rationale for Emission Standards for New Fossil Fuel-Fired Boilers and IGCCs

A. Overview

In this section we explain our rationale for emission standards for new fossil fuel-fired boiler and IGCC EGUs,

[167] 1970 Senate Commitee Report at 2.

[168] 116 Cong. Rec. 32,917 (1970) (statement of Sen. Muskie).

[169] *See* 116 Cong. Rec. 42,385 (Dec. 18, 1970) (statement of Sen. Muskie) (sources of hazardous air pollutants could be required to close due to absence of control techniques).

[170] *International Harvester Co.* v. *EPA,* 478_F.2d at 640.

[171] *NRDC* v. *EPA,* 489 F.3d at 1376.

[172] Standards of Performance for New Stationary Sources, Primary Copper, Zinc, and Lead Smelters, 41 FR 2331, 2333 (Jan. 15, 1976).

[173] 41 FR 2333.

which are based on our proposal that efficient generating technology implementing partial CCS is the BSER adequately demonstrated for those sources.

As noted, CAA section 111 and subsequent court decisions establish a set of factors for the EPA to consider in a BSER determination, including criteria listed in CAA section 111 or identified in the court decisions and the underlying purposes of section 111. Key factors include: emission reductions, technical feasibility, costs, and encouragement of technology. Other factors, such as energy impacts, may also be important. As also noted, the EPA has discretion in balancing those factors, and may balance them differently in promulgating standards for different source categories.

The EPA considered three alternative control technology configurations as potentially representing the BSER for new fossil fuel-fired boilers and IGCC units. Power company announcements indicate that the few new coal-fired projects that may occur will likely consider one or more of these three configurations. The three alternatives are: (1) Highly efficient new generation technology that does not include any level of CCS, (2) highly efficient new generation technology with ''full capture'' CCS (that is, CCS with capture of at least 90 percent CO_2 emissions) and (3) highly efficient new generation technology with ''partial capture'' CCS (that is, CCS with capture of a lower level of CO_2 emissions).

We discuss each of these alternatives below, and explain why we propose that partial capture CCS qualifies as the BSER. We first discuss the technical systems that we considered for the BSER, our evaluations of them, and our reasons for determining that only partial CCS meets the criteria to qualify as the BSER. We include in this discussion our rationale for selecting 1,100 lb CO_2/MWh as the emission limitation for these sources and why we are considering a range from 1,000 to 1,200 lb CO_2/MWh for the final rule. We next discuss our rationale for allowing an 84-operating-month averaging period as an alternative compliance method, with the requirement that sources choosing that method meet a limit of between 1,000 lb CO_2/MWh and 1,050 lb CO_2/MWh.[174] We then explain our rationale for the requirements for geologic sequestration.[175]

B. Identification of the Best System of Emission Reduction

1. Highly Efficient New Generation Without CCS Technology

Some commenters on the April 2012 proposal suggested that the emission limitation for new coal-fired EGUs should be based on the performance of highly efficient generation technology that does not include CCS, such as (i) a supercritical[176] pulverized coal (SCPC) or CFB boiler, or (ii) a modern, well-performing IGCC unit.

These options are technically feasible. However, we do not consider them to qualify as the BSER for the following reasons:

a. Lack of Significant CO_2 Reductions

Because of the large amount of CO_2 emissions from solid-fuel fired power plants, it is important, in promulgating a standard of performance for these sources, to give effect to the purpose of CAA section 111 of providing ''as much [emission reduction] as practicable.''[177] Accordingly, we reviewed the emission rates of efficient PC and CFB units. According to the DOE/NETL estimates, a new subcritical PC unit firing bituminous coal would emit approximately 1,800 lb CO_2/MWh,[178] a new SCPC unit using bituminous coal would emit nearly 1,700 lb CO_2/MWh, and a new IGCC unit[179] would emit about 1,450 lb CO_2/MWh.[180]

New power sector projects using coal as a primary fuel that have been proposed or are currently under construction are generally SCPC or IGCC projects. For example, since 2007, almost all coal-fired EGUs that have broken ground have been high performing versions of SCPC or IGCC projects.[181] Among those plants are: (1) AEP's John W. Turk, Jr. Power Plant, a 600 MW ultra-supercritical[182] PC (USCPC) facility located in the southwest corner of Arkansas; (2) Duke Power's Edwardsport plant, a 618 MW coal IGCC unit located in Knox County, Indiana; and (3) Southern Company's Kemper County Energy Facility, a 582 MW lignite IGCC unit located in Kemper County, Mississippi. These facilities all use advanced generation technology: Turk, as noted, is an ultra-supercritical boiler; Edwardsport is an IGCC unit that is ''CCS ready;'' and Kemper is an IGCC unit that will implement partial CCS.

Under these circumstances, in this rule, identifying a new supercritical unit as the BSER and requiring the associated emission limitation, would provide little meaningful CO_2 emission reductions for this source category. As noted, for the most part, new sources are already designed to achieve at least that emission limitation. Identifying IGCC as the BSER and requiring the associated emission limitation, would provide some CO_2 emission reductions from the segment of the industry that would otherwise construct new PC units, but not from the segment of the industry that would already construct new IGCC units.

As a result, emission reductions in the amount that would result from an emission standard based on SCPC/USCPC or even IGCC as the BSER would not be consistent with the purpose of CAA section 111 to achieve ''as much [emission reduction] as practicable.''[183] As we discuss below, identifying CCS-partial capture as the BSER would provide for significantly greater emissions reductions.

b. Lack of Incentive for Technological Innovation

Identifying highly efficient generation technology as the BSER would not achieve another purpose of CAA section 111, to encourage the development and implementation of control technology.

[174] This is on a gross output basis. All emission rates in this section are on a gross output basis unless specifically noted otherwise.

[175] It should be noted that the standard of performance that we propose in this rulemaking for new fossil-fired utility steam-generating units of 1,100 lb CO_2/MWh applies to new liquid oil- and natural-gas fired units, as well as solid fuel-fired units. However, we are not conducting a separate analysis of the best system of emission reduction for new liquid oil- and natural gas-fired units. That is because no new utility steam-generating units designed to be fired primarily with liquid oil or natural gas have been built for many years, and none are expected to be built in the foreseeable future, due to the significantly lower costs of building combustion turbines to be fired with those fuels.

[176] 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 increases the amount of energy within the steam, so that more energy can be extracted by the steam turbine, which in turn leads to increased efficiency and lower emissions.

[177] Sierra Club, F.2d at 327 & n. 83 (quoting 44 FR 33581/3—33582/1).

[178] Exhibit ES–2 from ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'', Revision 2, Report DOE/NETL–2010/1397 (November 2010).

[179] ''Case 1'' from Exhibit ES–2 from ''Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity'', Revision 2, Report DOE/NETL–2010/1397 (November 2010).

[180] The comparable emissions on a net basis are: subcritical PC—1,888 lb CO_2/MWh; supercritical PC—1,768 lb CO_2/MWh; and IGCC—1,723 lb CO_2/MWh.

[181] The only exception that we are aware of is the Virginia City subcritical CFB unit.

[182] Ultra-supercritical (USC) and advanced ultra-supercritical (A–USC) are terms often used to designate a coal-fired power plant design with steam conditions well above the critical point.

[183] *Sierra Club,* F.2d at 327 & n. 83 (quoting 44 FR 33581/3—33582/1).

At present, CCS technologies are the most promising options to achieve significant reductions in CO_2 emissions from fossil-fuel fired utility boilers and IGCC units. A standard based on the performance of highly efficient coal-fired generation does not advance the development and implementation of control technologies that reduce CO_2 emissions. In addition, highly efficient generation technology does not develop control technology that is transferrable to existing EGUs. Further, highly efficient generation technology does not necessarily promote the development of generation technologies that would minimize the auxiliary load requirements and costs of future CCS requirements (e.g., developing an IGCC design where the costs and auxiliary load requirements of adding CCS are minimized).

On the contrary, such a standard could impede the advancement of CCS technology by creating regulatory disincentives for such technology. In 2011, AEP deferred construction of a large-scale CCS retrofit demonstration project on one of their coal-fired power plants because the state's utility regulators would not approve cost recovery for CCS investments without a regulatory requirement to reduce CO_2 emissions. AEP's chairman was explicit on this point, stating in a July 17, 2011 press release announcing the deferral:

> We are placing the project on hold until economic and policy conditions create a viable path forward . . . We are clearly in a classic 'which comes first?' situation. The commercialization of this technology is vital if owners of coal-fueled generation are to comply with potential future climate regulations without prematurely retiring efficient, cost-effective generating capacity. But as a regulated utility, it is impossible to gain regulatory approval to recover our share of the costs for validating and deploying the technology without federal requirements to reduce greenhouse gas emissions already in place. The uncertainty also makes it difficult to attract partners to help fund the industry's share.[184]

As we discuss below, regulatory requirements for CO_2 reductions with some level of CCS as the BSER will promote further development of the technology.

2. Carbon Capture and Storage

We have also considered whether the emission limitation for new coal-fired EGUs should be based on the performance of CCS, including either ''full capture'' CCS that treats the entire flue gas or syngas stream to achieve on the order of 90 percent reduction in CO_2 emissions, or ''partial capture'' CCS that achieves some level less than 90 percent of capture.

We propose that implementation of partial capture CCS technology is the BSER for new fossil fuel-fired boilers and IGCC units because it fulfills the criteria established under CAA section 111. In the sections that follow, we explain the technical configurations that facilitate full and partial capture, describe the operational flexibilities that partial capture offers, and then identify and justify the emission rate that we propose based on partial capture. After that, we discuss the criteria for BSER, and describe why partial capture meets those criteria and why full capture does not. Among other things, partial capture provides meaningful emission reductions, it has been adequately demonstrated to be technically feasible, it can be implemented at a reasonable cost, and it promotes deployment and further development of the technology.

3. Technical Configurations for CCS

The DOE's National Energy Technology Laboratory (NETL) performed a study to establish the cost and performance for a range of CO_2 capture levels for new SCPC and IGCC power plants.[185] The study identified technical configurations that were tailored to achieve a specific level of carbon capture.

a. SCPC

For the new SCPC case, the study assumed a new SCPC boiler with a combination of low-NO_X burners (LNB) with overfire air (OFA) and a selective catalytic reduction (SCR) system for NO_X control. The plant was assumed to have a fabric filter and a wet limestone flue gas desulfurization (FGD) scrubber for particulate matter and sulfur dioxide (SO_2) control, respectively. The plant was also assumed to have a sodium hydroxide (NaOH) polishing scrubber to ensure that the flue gas entering the CO_2 capture system has a SO_2 concentration of 10 ppmv or less. The SCPC plant was equipped with Fluor's Econamine FG Plus^{SM} process for post-combustion CO_2 capture via temperature swing absorption with a monoethanolamine (MEA) solution as the chemical solvent.

The study's authors identified two options for achieving partial capture (i.e., less than 90 percent CO_2 capture) in the SCPC unit. The first option was to process the entire flue gas stream through the MEA capture system at reduced solvent circulation rates. The second option was to maintain the same high solvent circulation rate and steam stripping requirement as would be used for full capture but only treat a portion of the total flue gas stream. The authors determined that the second approach—the ''slip stream'' approach—was the most economical. The authors further noted that the cost of CO_2 capture with an amine scrubbing process is dependent on the volume of gas being treated, and a reduction in flue gas flow rate will: (1) Decrease the quantity of energy consumed by flue gas blowers, (2) reduce the size of the CO_2 absorption columns, and (3) trim the cooling water requirement of the direct contact cooling system. The slip stream approach leads to lower capital and operating costs. All of the partial capture cases in the NETL study assumed this approach.

b. IGCC

For a new IGCC unit, the product syngas would contain primarily H_2, CO and some lesser amount of CO_2.[186] The amount of CO_2 can be increased by ''shifting'' the composition via the catalytic water-gas shift (WGS) reaction. This process involves the catalytic reaction of steam (''water'') with CO (''gas'') to form H_2 and CO_2. An emission standard that requires partial capture of CO_2 from the syngas could be met by adjusting the level of CO_2 in the syngas stream by controlling the level of syngas ''shift'' prior to treatment in the pre-combustion acid gas treatment system.

For a new IGCC EGU, the study's authors assumed the use of the GE gasifier coupled with a variety of potential configurations (i.e., no WGS reactor, single-stage WGS, two-stage WGS, varying WGS bypass ratios, and CO_2 scrubber removal efficiency). The study evaluated a number of IGCC plant configurations. The first was an IGCC that used the Selexol™ process for acid gas control (i.e., hydrogen sulfide (H_2S) and CO_2) but no WGS reactor. This unit was capable of CO_2 capture ranging from zero up to 25 percent. The no-CO_2 capture case employed a one-stage Selexol™ unit for H_2S control and the 25 percent CO_2 capture case utilized a two-stage Selexol™ unit to maximize CO_2 capture from the unshifted syngas (i.e., >90 percent of the CO_2 from the unshifted syngas was captured in the second stage Selexol™ scrubber).

[184] *http://www.aep.com/newsroom/newsreleases/?id=1704.*

[185] ''Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture'', DOE/NETL–2011/1498, May 27, 2011.

[186] The amount of CO_2 in un-shifted syngas depends upon the specific gasifier technology used, the operating conditions, and the fuel used; but is typically less than 20 volume percent (*http://www.netl.doe.gov/technologies/coalpower/gasification/gasifipedia/4-gasifiers/4-3_syngas-table2.html*).

To achieve moderate levels of partial CO_2 capture—approximately 25 to 75 percent—the IGCC was configured with a single-stage WGS reactor with bypass and a two-stage Selexol™ unit. Varying the extent of the WGS reaction by controlling the amount of syngas that was processed through the WGS reactor (by controlling the amount that bypassed the WGS reactor) manipulated the level of CO_2 capture. As more syngas is processed through the WGS reactor, the steam demand increases. The Selexol™ removal efficiency was manipulated by varying the solvent circulation rate. Thus, a facility using this configuration could select or ''dial in'' a level of control of between 25–75 percent.

To achieve higher CO_2 capture levels—levels greater than 75 percent—the IGCC was configured with a two-stage WGS with bypass and the two-stage acid gas (Selexol™) scrubbing system. The facility could ''dial in'' a level of control of between 25 to greater than 90 percent by controlling the WGS bypass and the Selexol™ scrubber recirculation rates.

The water-gas shift involves the catalytic reaction of carbon monoxide and steam. Since the syngas initially contains primarily CO and H_2, this shift reaction diminishes the concentration of CO and enriches the concentration of H_2 in the pre-combustion syngas stream via the following reaction:

$$CO + H_2O \xrightarrow{\Delta} CO_2 + H_2$$

An unshifted or partially shifted syngas can be combusted using a typical combustion turbine. However, as the level of H_2 in the syngas increases, the more the syngas must be diluted with N_2 or air. Very high levels of H_2 in the syngas stream require use of a specialty hydrogen turbine.

4. Operational and Design Flexibility

To this point, most of the studies involving research, development and demonstration of carbon capture technology, along with most of the studies that have modeled the costs and implementation of such technology have assumed capture requirements of 90 percent for fossil fuel-fired power plants (''full capture''). However, the EPA believes that partial capture provides significant benefits because an emission limit based on partial capture offers operators considerable operational flexibility. With such emission limits, project developers would have the option of designing and installing CO_2 capture technology at a size sufficient to treat the entire flue gas stream, with the capability to meet CO_2 emission limits that are much lower than required. The operator of the plant could then choose to achieve those deeper capture rates during non-peak electricity demand periods and to achieve lesser capture rates (and thus generate more electricity) during peak electricity demand periods. This type of operational flexibility provides owners and operators the opportunity to optimize the operation and minimize the cost of CCS in new fossil fuel-fired projects.

In addition, an emission standard that can be met with partial capture offers the opportunity for design flexibility. A project developer of a new conventional coal-fired plant (i.e., a new supercritical PC or CFB) could install post-combustion CO_2 scrubbers that have been designed and sized to treat only a portion of the flue gas stream.

For a new IGCC unit, as noted, an emission standard that requires partial capture of CO_2 offers operational flexibility because the standard could be met by adjusting the level of CO_2 in the syngas stream by controlling the level of syngas ''shift'' prior to treatment in the pre-combustion acid gas treatment system.

C. Determination of the Level of the Standard

Once the EPA has determined that a technology has been adequately demonstrated based on cost and other factors, including the impact a standard will have on further technology development, and therefore represents BSER, the EPA must establish an emission standard. In this case, for new fossil fuel-fired boiler and IGCC EGUs, the EPA proposes to find that the level of partial capture of CO_2 that qualifies as the BSER supports a standard of 1,100 lb CO_2/MWh on a gross basis. The level of the standard is based on the emission reductions that can be achieved by an IGCC with a single-stage WGS reactor and a two-stage acid gas removal system. According to the DOE/NETL partial capture study, an IGCC with this configuration would be expected to achieve a CO_2 emission reduction of 25 to 75 percent, which corresponds to emissions of approximately 1,060 and 380 lb CO_2/MWh-gross, respectively. The EPA is proposing a standard of performance of 1,100 lb CO_2/MWh-gross, which is the high end of this range, for several reasons.

First, both a new IGCC and a conventional coal-fired boiler (PC or CFB), can achieve this emission standard at a reasonable cost and the standard is based on technology that has been adequately demonstrated.

The partial capture requirement and standard of performance will allow new IGCC project developers to minimize the need for multi-stage water-gas shift reactors (and the associated steam requirement) and will allow for the continued use of conventional syngas combustion turbines (rather than requiring the use of advanced hydrogen turbines). Second, this partial capture configuration will provide operators with operational flexibility. Third, this level of the standard best promotes further enhancement of the performance of existing technology and promotes continued development of new, better performing technology. Because the proposed emission standard would require only partial implementation of CCS, it will provide developers with the opportunity to investigate new emerging technologies that may achieve deeper reductions at lower or comparable cost. For instance, developers could build plants with the capacity to achieve deeper CO_2 reductions and choose to employ those greater capture rates during non-peak periods, and then employ lower capture rates (and thus generate more electricity) during peak periods.

While the EPA is proposing an emission rate of 1,100 lb CO_2/MWh, 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 this proposal, we are considering a range of 1,000 to 1,200 lb CO_2/MWh-gross for the final rule. An emission rate of 1,200 lb CO_2/MWh-gross could potentially be met by an IGCC unit that does not include a WGS reactor (although an owner/operator might still use a WGS reactor or co-fire natural gas to maintain operational flexibility), thus further reducing the capital and operating costs. An emission limit of 1,000 lb CO_2/MWh-gross would provide greater emission reductions, could still be achieved with a single WGS reactor, and would also advance CCS technology but would offer less operational flexibility and increase costs.

We are not currently considering a standard below 1,000 lb CO_2/MWh. With a standard of 1,000 lb CO_2/MWh, an owner/operator of an IGCC facility could burn natural gas during periods when the gasifier is unavailable while still maintaining an annual emissions rate that is below the NSPS. In addition, an owner/operator could elect to co-fire natural gas as an option to reduce the amount of CCS required to comply with the NSPS. With a standard below 1,000 lb CO_2/MWh, those operational flexibilities may not be available. We request that commenters who suggest

emission rates below 1,000 lb CO_2/MWh address potential concerns about operational flexibility.

We are not currently considering a standard above 1,200 lb CO_2/MWh because at that level, the NSPS would not necessarily promote the development of CO_2 emissions control technology or provide significant CO_2 reductions. At an emissions rate of 1,300 lb CO_2/MWh, IGCC facilities would only be required to capture approximately 10 percent of the CO_2, and many designs would have a sufficient compliance margin that they would not need to use a WGS reactor. Further, an owner/operator of an IGCC facility could comply with this standard without the use of any CCS. For example, a new IGCC facility designed to co-fire 20 percent natural gas or using fuel cells instead of combustion turbines could comply with an emissions rate of 1,300 lb CO_2/MWh without the use of CCS. An emissions rate of 1,400 lb CO_2/MWh would provide even less technology development and emissions reductions. At an emissions rate of 1,400 lb CO_2/MWh, an IGCC facility could comply with no WGS reactor and by (i) capturing less than 5 percent of the CO_2, (ii) co-firing less ten percent natural gas with no CCS, or (iii) using integrated solar thermal for supplemental steam production without CCS. In addition, at an emissions rate of 1,400 lb CO_2/MWh a PC or CFB could use integrated combustion turbines or fuel cells for boiler feedwater heating, supplemental steam production, or for preheated air for the boiler as an alternative to CCS. We request that commenters who suggest emission rates above 1,200 lb CO_2/MWh address potential concerns about providing adequate reductions and technology development to be considered BSER.

The next several sections review the factors for determining BSER and explain why partial capture at the level we are proposing meets those requirements, as well as why full capture does not meet some of them.

D. Extent of Reductions in CO_2 Emissions

The proposed standard of 1,100 lb CO_2/MWh will provide meaningful reductions in emissions. As mentioned earlier, the DOE/NETL has estimated that a new SCPC boiler using bituminous coal would emit 1,675 lb CO_2/MWh. The DOE/NETL has also estimated that a new IGCC unit would emit 1,434 lb CO_2/MWh. The emissions would be higher for units utilizing subbituminous coal or lignite and will vary when utilizing other fossil fuels such as petroleum coke or mixtures of fuels. We estimate that this standard will result in reduction in emissions of at least 40 percent when compared to the expected emissions of a new SCPC boiler.

E. Technical Feasibility

The EPA proposes to find that partial CCS is feasible because each step in the process has been demonstrated to be feasible through an extensive literature record, fossil fuel-fired industrial plants currently in commercial operation and pilot-scale fossil fuel-fired EGUs currently in operation, the progress towards completion of construction of fossil fuel-fired EGUs implementing CCS at commercial scale. This literature record and experience demonstrate that partial CCS is achievable for all types of new boiler and IGCC configurations. Although much of this information also serves to demonstrate the technical feasibility of full capture, we note that several of the CCS projects that are the furthest along are partial capture projects, which further supports our view that partial capture is BSER.

1. Literature

The current status of CCS technology was described and analyzed by the 2010 Interagency Task Force on CCS, established by President Obama on February 3, 2010, co-chaired by the DOE and the EPA, and composed of 14 executive departments and federal agencies. The Task Force was charged with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing five to ten commercial demonstration projects online by 2016. The Task Force found that, although early CCS projects face economic challenges related to climate policy uncertainty, first-of-a-kind technology risks, and the current cost of CCS relative to other technologies, there are no insurmountable technological, legal, institutional, regulatory or other barriers that prevent CCS from playing a role in reducing GHG emissions.[187]

The Pacific Northwest National Laboratory (PNNL) recently prepared a study that evaluated the development status of various CCS technologies for the DOE.[188] The study addressed the availability of capture processes, transportation options (CO_2 pipelines), injection technologies, and measurement, verification and monitoring technologies. The study concluded that, in general, CCS is technically viable today and that key component technologies of complete CCS systems have been deployed at scales large enough to meaningfully inform discussions about CCS deployment on large commercial fossil-fired power plants.

In addition, DOE/NETL has prepared other reports—in particular their ''Cost and Performance Baseline'' reports,[189] including one on partial capture [190]—that further support our proposed determination of the technical feasibility of partial capture.

2. Capture, Transportation and Storage Technologies

Each of the core components of CCS—CO_2 capture, compression, transportation and storage—has already been implemented and, in fact, in some instances, implemented on a commercial scale. The U.S. experience with large-scale CO_2 injection, including injection at enhanced oil and gas recovery projects, combined with ongoing CCS research, development, and demonstration programs in the U.S. and throughout the world, provide confidence that the capture, transport, compression, and storage of large amounts of CO_2 can be achieved.

a. CO_2 Capture Technology

Capture of CO_2 from industrial gas streams has occurred since the 1930s, through use of a variety of approaches to separate CO_2 from other gases. These processes have been used in the natural gas industry and to produce food and chemical-grade CO_2.

Although current capture technologies are feasible, the costs of CO_2 capture and compression represent the largest barriers to widespread commercialization of CCS. Currently available CO_2 capture and compression processes are estimated to represent 70 to 90 percent of the overall CCS costs.[191]

In general, CO_2 capture technologies applicable to coal-fired power generation can be categorized into three approaches: [192]

[187] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010), page 7.

[188] ''An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009'', PNNL–18520, Pacific Northwest National Laboratory, Richland, WA, June 2009. Available at: *http://www.pnl.gov/main/publications/external/technical_reports/PNNL-18520.pdf.*

[189] The ''Cost and Performance Baseline'' reports are a series of reports by DOE/NETL that establish estimates for the cost and performance of combustion- and gasification-based power plants—all with and without CO_2 capture and storage. Available at *www.netl.doe.gov/energy-analyses/baseline_studies.html.*

[190] ''Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture'', DOE/NETL–2011/1498, May 27, 2011.

[191] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010).

[192] *Id* at 29.

• Pre-combustion systems that are designed to separate CO_2 and H_2 in the high-pressure syngas produced at IGCC power plants.

• Post-combustion systems that are designed to separate CO_2 from the flue gas produced by fossil-fuel combustion in air.

• Oxy-combustion that uses high-purity O_2, rather than air, to combust coal and thereby produce a highly concentrated CO_2 stream.

Each of these three carbon capture approaches (pre-combustion, post-combustion, and oxy-combustion) is technologically feasible. However, each results in increased capital and operating costs and decreased electricity output (that is, an energy penalty), with a resulting increase in the cost of electricity. The energy penalty occurs because the CO_2 capture process uses some of the energy (e.g., electricity, steam, heat) produced from the plant.

b. CO_2 Transportation

Carbon dioxide has been transported via pipelines in the U.S. for nearly 40 years. Approximately 50 million metric tons of CO_2 are transported each year through 3,600 miles of pipelines. Moreover, a review of the 500 largest CO_2 point sources in the U.S. shows that 95 percent are within 50 miles of a possible geologic sequestration site,[193] which would lower transportation costs. There are multiple factors that contribute to the cost of CO_2 transportation via pipelines including but not limited to: availability and acquisition of rights-of-way for new pipelines, capital costs, operating costs, length and diameter of pipeline, terrain, flow rate of CO_2, and the number of sources utilizing the pipeline. At the same time, studies and DOE quality guidelines have shown CO_2 pipeline transport costs in the $1 to $4 dollar per ton of CO_2 range.[194] [195] [196] [197] For these reasons, the transportation component of CCS is well-established as technically feasible and is not a significant component of the cost of CCS.

c. CO_2 Storage

(i) Current availability of geologic sequestration

Existing project and regulatory experience (including EOR), research, and analogs (e.g. naturally existing CO_2 sinks, natural gas storage, and acid gas injection), indicate that geologic sequestration is a viable long term CO_2 storage option. While EPA has confidence that geologic sequestration is technically feasible and available, EPA recognizes the need to continue to advance the understanding of various aspects of the technology, including, but not limited to, site selection and characterization, CO_2 plume tracking, and monitoring. On-going Federal government efforts such as DOE/NETL's activities to enhance the commercial development of safe, affordable, and broadly deployable CCS technologies in the United States, including: Research, development, and demonstration of CCS technologies and the assessment of the country's geologic capacity to store carbon dioxide, are particularly important.[198] Furthermore, this rule, including the information collected through the GHG Reporting Program, will facilitate further deployment of CCS and advancements in the technology. Information collected under the GHG Reporting Program will provide a transparent means for EPA and the public to continue to evaluate the effectiveness of CCS, including improvements needed in monitoring technologies.

The viability of geologic sequestration of CO_2 is based on a demonstrated understanding of the fate of CO_2 in the subsurface. Geologic sequestration occurs through a combination of structural and stratigraphic trapping (trapping below a low permeability confining layer), residual CO_2 trapping (retention as an immobile phase trapped in the pore spaces of the storage formation), solubility trapping (dissolution in the in situ formation fluids), mineral trapping (reaction with the minerals in the storage formation and confining layer to produce carbonate minerals), and preferential adsorption trapping (adsorption onto organic matter in coal and shale).[199] [200] These mechanisms are functions of the physical and chemical properties of CO_2 and the geologic formations into which the CO_2 is injected.

Project and research experience continues to add to the confidence in geologic sequestration as a viable CO_2 reduction technology. In addition to the four existing commercial CCS facilities in other countries,[201] multiple studies have been completed that have demonstrated geologic sequestration of CO_2 as well as have improved technologies to monitor and verify that the CO_2 remains sequestered.[202] For example, CO_2 has been injected in the SACROC Unit in the Permian basin since 1972 for enhanced oil recovery purposes. A study evaluated this project, and estimated that about 93 million metric tons of CO_2 were injected and about 38 million metric tons were produced from 1972 to 2005, resulting in a geologic CO_2 accumulation of 55 million metric tons of CO_2.[203] This study evaluated the ongoing and potential CO_2 trapping occurring through various mechanisms using modeling and simulations, and collection and analysis of seismic surveys and well logging data. The monitoring at this site demonstrated that CO_2 can indeed become trapped in geologic formations. Studies on the permanence of CO_2 storage in geologic sequestration have been conducted internationally as well. For example, the Gorgon Carbon Dioxide Injection Project and Collie-South West CO_2 Geosequestration Hub project in Australia have both demonstrated geologic CO_2 trapping mechanisms.[204]

Numerous other field studies, for example those conducted by the DOE/

[193] JJ Dooley, CL Davidson, RT Dahowski, MA Wise, N Gupta, SH Kim, EL Malone (2006), Carbon Dioxide Capture and Geologic Storage: A Key Component of a Global Energy Technology Strategy to Address Climate Change. Joint Global Change Research Institute, Battelle Pacific Northwest Division. PNWD–3602. College Park, MD.

[194] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010).

[195] McCollum, D., Ogden, J., 2006. Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity. Institute of Transportation Studies, University of California, Davis, Davis, CA.

[196] McCoy, S., E.S. Rubin and M.B. Berkenpas, 2008. Technical Documentation: The Economics of CO2 Transport by Pipeline Storage in Saline Aquifers and Oil Reserves. *Final Report,* Prepared by Carnegie Mellon University, Pittsburgh, PA for U.S. Department of Energy, National Energy Technology Center, Pittsburgh, PA.

[197] DOE/NETL. (2013). Carbon Dioxide Transport and Storage Costs in NETL Studies, Quality Guidelines for energy system studies. March 2013. DOE/NETL–2013/1614.

[198] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010).

[199] Intergovernmental Panel on Climate Change. (2005). *Special Report on Carbon Dioxide Capture and Storage.* Retrieved from *http://www.ipcc.ch/pdf/special-reports/srccs/srccs_chapter5.pdf.*

[200] Benson, Sally M. and David R. Cole. (2008). *CO_2 Sequestration in Deep Sedimentary Formations.* Elements, Vol. 4, pp. 325–331.

[201] Sleipner in the North Sea, Snøhvit in the Barents Sea, In Salah in Algeria, and Weyburn in Canada.

[202] Report of the Interagency Task Force on Carbon Capture and Storage (August 2010).

[203] Han, Weon Shik et al. (2010). *Evaluation of trapping mechanisms in geologic CO_2 sequestration: Case study of SACROC northern platform, a 35-year CO_2 injection site.* American Journal of Science Online April 2010 vol. 310 no. 4 282–324. Retrieved from: *http://www.ajsonline.org/content/310/4/282.abstract.*

[204] Sewell, Margaret, Frank Smith and Dominique Van Gent. Western Australia Greenhouse Gas Capture and Storage: A tale of two projects. (2012) Australian Department of Resources, Energy and Tourism and Western Australia Government of Western Australia. Retrieved from *http://cdn.globalccsinstitute.com/sites/default/files/publications/39961/ccsinwareport-opt.pdf.*

NETL Regional Carbon Sequestration Partnerships, have been completed that demonstrate CO_2 trapping mechanisms working in geologic formations in smaller scale projects. Examples of these DOE/NETL studies include: [205]

- Midwest Regional Carbon Sequestration Partnership Michigan Basin Phase II Validation Test, which injected approximately 60,000 metric tons of CO_2 over two periods from February to March 2008 (~10,000 metric tons) and from January to July 2009 (~50,000 metric tons).
- Midwest Geologic Sequestration Consortium Loudon, Mumford Hills, and Sugar Creek Phase II Validation Test, which consisted of injecting over 14,000 tons of CO_2 across three EOR-scale field tests.
- Southwest Regional Partnership on Carbon Sequestration (SWP) San Juan Basin Phase II Validation Test, which injected 16,700 metric tons into the coal layers of the Fruitland Formation.

Geologic storage potential for CO_2 is widespread and available throughout the U.S. and Canada. Estimates based on DOE studies indicate that areas of the U.S. with appropriate geology have a storage potential of 2,300 billion to more than 20,000 billion metric tons of CO_2 in deep saline formations, oil and gas reservoirs and un-mineable coal seams.[206] Other types of geologic formations such as organic rich shale and basalt may also have the ability to store CO_2; and the DOE is currently evaluating their potential storage capacity. While these are estimates, each potential geologic sequestration site must undergo appropriate site characterization to ensure that the site can safely and securely store CO_2. Estimates of CO_2 storage resources by state/province are compiled by the DOE's National Carbon Sequestration Database and Geographic Information System (NATCARB).

Further evidence of the widespread availability CO_2 storage reserves in the U.S. comes from the Department of Interior's U.S. Geological Survey (USGS) which has recently completed a comprehensive evaluation of the technically accessible storage resource for carbon storage for 36 sedimentary basins in the onshore areas and State waters of the United States.[207] The USGS assessment estimates a mean of 3,000 billion metric tons of subsurface CO_2 storage potential across the United States. For comparison, this amount is 500 times the 2011 annual U.S. energy-related CO_2 emissions of 5.5 Gigatons (Gt).[208]

Nearly every state in the U.S. has or is in close proximity to formations with carbon storage potential including vast areas offshore.

(ii) Current availability of enhanced oil and gas recovery

Geologic storage options also include use of CO_2 in EOR, which is the injection of fluids into a reservoir to increase oil production efficiency. EOR is typically conducted at a reservoir after production yields have decreased from primary production. Fluids commonly used for EOR include brine, fresh water, steam, nitrogen, alkali solutions, surfactant solutions, polymer solutions, and CO_2. EOR using CO_2, sometimes referred to as 'CO_2 flooding' or CO_2-EOR, involves injecting CO_2 into an oil reservoir to help mobilize the remaining oil and make it available for recovery. The crude oil and CO_2 mixture is produced, and sent to a separator where the crude oil is separated from the gaseous hydrocarbons and CO_2. The gaseous CO_2-rich stream then is typically dehydrated, purified to remove hydrocarbons, recompressed, and re-injected into the oil or natural gas reservoir to further enhance recovery.

CO_2-EOR has been successfully used at many production fields throughout the U.S. to increase oil recovery. The oil and natural gas industry in the United States has over 40 years of experience of injection and monitoring of CO_2 in the deep subsurface for the purposes of enhancing oil and natural gas production. This experience provides a strong foundation for the injection and monitoring technologies that will be needed for successful deployment of CCS.

Monitoring CO_2 at EOR sites can be an important part of the petroleum reservoir management system to ensure the CO_2 is effectively sweeping the oil zone, and can be supplemented by techniques designed to detect CO_2 leakage. Recently many studies have been conducted to better understand the fate of injected CO_2 at well-established, operational EOR sites. A large number of methods are available to monitor surface and subsurface leakage at EOR sites. Some recent studies are presented below.

- At the SACROC field in the Permian Basin, the Texas Bureau of Economic Geology conducted an extensive groundwater sampling program to look for evidence of CO_2 leakage in the shallow freshwater aquifers. At the time of the study (2011), the SACROC field had injected 175 million metric tons of CO_2 over 37 years. No evidence of leakage was detected.[209]
- An extensive CO_2 leakage monitoring program was conducted by a third party (International Energy Agency Greenhouse Gas Programme) for 10 years at the Weyburn oil field in Saskatchewan, during which time over 16 million tonnes of CO_2 have been stored. A comprehensive analysis of surface and subsurface monitoring methods was conducted and resulted in a best practices manual for CO_2 monitoring at EOR sites.[210]
- The Texas Bureau of Economic Geology has also been testing a wide range of surface and subsurface monitoring tools and approaches to document storage efficiency and storage permanence at a CO_2 EOR site in Mississippi.[211] The Cranfield Field, under CO_2 flood by Denbury Onshore LLC, is a depleted oil and gas reservoir that injected greater than 1.2 million tons/year during the tests. The preliminary findings demonstrate the availability and effectiveness of many different monitoring techniques for tracking CO_2 underground and detecting CO_2 leakage.

The Department of Energy has conducted numerous evaluations of CO_2

[205] DOE/NETL. (2012). *Best Practices for: Monitoring, Verification, and Accounting of CO2 Stored in Deep Geologic Formations—2012 Update.* DOE/NETL–2012/1568. Retrieved from *http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM-MVA-2012.pdf.*

[206] The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL).

[207] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources—Results: U.S. Geological Survey Circular 1386, 41 p., *http://pubs.usgs.gov/fs/2013/1386/.*

[208] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources—Summary: U.S. Geological Survey Factsheet 2013–3020, 6p.*http://pubs.usgs.gov/fs/2013/3020/.*

[209] K.D. Romanak, R.C. Smyth, C. Yang, S.D. Hovorka, M. Rearick, J. Lu. (2011). *Sensitivity of groundwater systems to CO_2: Application of a site-specific analysis of carbonate monitoring parameters at the SACROC CO_2-enhanced oil field.* GCCC Digital Publication Series #12–01. Retrieved from *http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=190.*

[210] Geoscience Publishing. (2012). *Best Practices for Validating CO_2 Geological Storage: Observations and Guidance from the IEAGHG Weyburn-Midale CO_2 Monitoring and Storage Project.* Brian Hitchon (Ed.).

[211] Hovorka, S.D., et al. (2011). *Monitoring a large volume CO_2 injection: Year two results from SECARB project at Denbury's Cranfield, Mississippi, USA:* Energy Procedia, v. 4, Proceedings of the 10th International Conference on Greenhouse Gas Control Technologies GHGT10, September 19–23, 2010, Amsterdam, The Netherlands, p. 3478–3485. GCCC Digital Publication #11–16. Retrieved from *http://www.sciencedirect.com/science/article/pii/S1876610211004711.*

monitoring techniques at EOR pilot sites throughout the U.S. as part of the Regional Sequestration Partnership Phase II and III programs. For example, in the Illinois Basin surface and subsurface monitoring techniques were tested at three short duration CO_2 injections. At one of the Illinois Basin sites, a landowner became concerned when excessive odor in a water well was observed. The ongoing groundwater monitoring program results were used to verify the odor was from a different origin.[212]

The EPA anticipates that many early geologic sequestration projects may be sited in active or depleted oil and gas reservoirs because these formations have been previously well characterized for hydrocarbon recovery, likely already have suitable infrastructure (e.g., wells, pipelines, etc.), and have an associated economic benefit of oil production. EOR sites including those that inject CO_2, are typically selected and operated with the intent of oil production; however, they may also be suitable for long term containment of CO_2. Although deep saline formations provide the largest CO_2 storage opportunity (2,102 to 20,043 billion metric tons), oil and gas reservoirs are currently estimated to have 226 billion metric tons of CO_2 storage resource.[213]

CO_2-EOR is the fastest-growing EOR technique in the U.S., providing approximately 281,000 barrels of oil per day in the U.S. which equals about 6 percent of U.S. crude oil production. The vast majority of CO_2-EOR is conducted in oil reservoirs in the U.S. Permian Basin, which extends through southwest Texas and southeast New Mexico. Other U.S. states where CO_2-EOR is utilized are Alabama, Colorado, Illinois, Kansas, Louisiana, Michigan, Mississippi, New Mexico, Oklahoma, Utah, and Wyoming. A well-established and expanding network of pipeline infrastructure supports CO_2-EOR in these areas. The CO_2 supply for EOR operations currently is largely obtained from natural underground formations or domes that contain CO_2. While natural sources of CO_2 comprise the majority of CO_2 supplied for EOR operations, recent developments targeting anthropogenic sources of CO_2 (e.g., ethanol plants, gas processing plants, refineries, power plants) have expanded or led to planned expansions in existing infrastructure related to CO_2-EOR. Several hundred miles of dedicated CO_2 pipeline is under construction, planned, or proposed that would allow continued growth in CO_2 supply for EOR.

Potential sources of CO_2 for EOR continue to increase as new projects are being planned or implemented. Based on an evaluation of publicly available sources, the EPA notes there are currently twenty-three industrial source CCS projects in twelve states that are either operational, under-construction, or actively being pursued which are or will supply captured CO_2 for the purposes of EOR.[214] This further demonstrates that CCS projects associated with large point sources are occurring due to a demand for CO_2 by EOR operations. Nationally, approximately 60 million metric tons of CO_2 were received for injection at EOR operations in 2012.[215] A recent study by DOE found that the market for captured CO_2 emissions from power plants created by economically feasible CO_2-EOR projects would be sufficient to permanently store the CO_2 emissions from 93 large (1,000 MW) coal-fired power plants operated for 30 years.[216] Based on all of these factors, the EPA anticipates opportunities to utilize CO_2-EOR operations for geologic storage will continue to increase.

Based on a recent resource assessment by the DOE, the application of next generation CO_2-EOR technologies would significantly increase oil production areas, further expanding the geographic extent and accessibility of CO_2-EOR operations in the U.S.[217] Additionally, oil and gas fields now considered to be 'depleted' may resume operation because of increased availability and decreased cost of anthropogenic CO_2, and developments in EOR technology, thereby increasing the demand for and accessibility of CO_2 utilization for EOR.

The use of CO_2 for EOR can significantly lower the net cost of implementing CCS. The opportunity to sell the captured CO_2 for EOR, rather than paying directly for its long-term storage, improves the overall economics of the new generating unit. According to the International Energy Agency (IEA), of the CCS projects under construction or at an advanced stage of planning, 70 percent intend to use captured CO_2 to improve recovery of oil in mature fields.[218]

d. Examples of CCS Demonstration Projects

The following is a brief summary of some examples of currently operating or planned CO_2 capture or storage systems, including, in some cases, components necessary for coal-fired power plant CCS applications.

AES's coal-fired Warrior Run (Cumberland, MD) and Shady Point (Panama, OK) power plants are equipped with amine scrubbers developed by ABB/Lummus. They were designed to process a slip stream of each plant's flue gas. At Warrior Run, approximately 110,000 metric tons of CO_2 per year are captured. At Shady Point 66,000 metric tons of CO_2 per year are captured. The CO_2 from both plants is used in the food processing industry.[219]

At the Searles Valley Minerals soda ash plant in Trona, CA, approximately 270,000 metric tons of CO_2 per year are captured from the flue gas of a coal-fired power plant via amine scrubbing and used for the carbonation of brine in the process of producing soda ash.[220]

A pre-combustion Rectisol® system is used for CO_2 capture at the Dakota Gasification Company's synthetic natural gas production plant located in North Dakota, which is designed to remove approximately 1.6 million metric tons of CO_2 per year from the synthesis gas. The CO_2 is purified and transported via a 200-mile pipeline for use in EOR operations in the Weyburn oilfield in Saskatchewan, Canada.

In September 2009, AEP began a pilot-scale CCS demonstration at its Mountaineer Plant in New Haven, WV. The Mountaineer Plant is a 1,300 MWe coal-fired unit that was retrofitted with Alstom's patented chilled ammonia CO_2 capture technology on a 20 MWe slip stream of the plant's exhaust flue gas. In May 2011, Alstom Power announced the successful operation of the chilled-

[212] DOE/NETL. (2012). *Best Practices for: Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations—2012 Update.* DOE/NETL–2012/1568. Retrieved from *http://www.netl.doe.gov/technologies/carbon_seq/refshelf/BPM-MVA-2012.pdf.*

[213] U.S. Department of Energy National Energy Technology Laboratory (2012). United States Carbon Utilization and Storage Atlas, Fourth Edition.

[214] See ''Documentation for the Summary of Carbon Dioxide Industrial Capture to Enhanced Oil Recovery Projects'' (Docket EPA–HQ–OAR–2013–0495).

[215] ''Opportunities for Utilizing Anthropogenic CO_2 for Enhanced Oil Recovery and CO_2 Storage'', Michael L. Godec, Advanced Resources International, June 11, 2013 presentation at the Introduction to CO_2 EOR Workshop, *http://na2050.org/introduction-to-carbon-dioxide-enhanced-oil-recovery-co2-eor.*

[216] ''Improving Domestic Energy Security and Lowering CO_2 Emissions with ''Next Generation'' CO_2-Enhanced Oil Recovery (CO_2-EOR)'', DOE/NETL–2011/1504 (June 20, 2011).

[217] Ibid.

[218] Tracking Clean Energy Progress 2013, International Energy Agency (IEA), Input to the Clean Energy Ministerial, OECD/IEA 2013.

[219] Dooley, J. J., et al. (2009). An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009. U.S. DOE, Pacific Northwest National Laboratory, under Contract DE–AC05–76RL01830.

[220] IEA (2009), World Energy Outlook 2009, OECD/IEA, Paris.

ammonia CCS validation project. The demonstration achieved capture rates from 75 percent (design value) to as high as 90 percent, and produced CO_2 at purity of greater than 99 percent, with energy penalties within a few percent of predictions. The facility reported robust steady-state operation during all modes of power plant operation including load changes, and saw an availability of the CCS system of greater than 90 percent.

AEP, with assistance from the DOE, had planned to expand the slip stream demonstration to a commercial scale, fully integrated demonstration at the Mountaineer facility. The commercial-scale system was designed to capture at least 90 percent of the CO_2 from 235 MW of the plant's 1,300 MW total capacity. Plans were for the project to be completed in four phases, with the system to begin commercial operation in 2015. However, in July 2011, AEP announced that it would terminate its cooperative agreement with the DOE and place its plans to advance CO_2 capture and storage technology to commercial scale on hold, citing the uncertain status of U.S. climate policy as a contributor to the decision.

Oxy-combustion of coal is being demonstrated in a 10 MWe facility in Germany. The Vattenfall plant in eastern Germany (Schwarze Pumpe) has been operating since September 2008. It is designed to capture 70,000 metric tons of CO_2 per year. A larger scale project—the FutureGen 2.0 Project—is in advanced stages of planning in the U.S.[221]

In June 2011, Mitsubishi Heavy Industries, an equipment manufacturer, announced the successful launch of operations at a 25 MW coal-fired carbon capture facility at Southern Company's Alabama Power Plant Barry. The demonstration captures approximately 165,000 metric tons of CO_2 annually at a CO_2 capture rate of over 90 percent. The captured CO_2 is being permanently stored underground in a deep saline geologic formation.

Southern Company has begun construction of Mississippi Power Kemper County Energy Facility. This is a 582 MW IGCC plant that will utilize local Mississippi lignite and include pre-combustion carbon capture to reduce CO_2 emissions by 65 percent. The captured CO_2 will be used for EOR in the Heidelberg Oil Fields in Jasper County, MS. The project is now more than 75 percent complete with start-up and operation expected to begin in 2014.

SaskPower's Boundary Dam CCS Project in Estevan, a city in Saskatchewan, Canada, is the world's largest commercial-scale CCS project of its kind. The project will fully integrate the rebuilt 110 MW coal-fired Unit #3 with available CCS technology to capture 90 percent of its CO_2 emissions. The facility is currently under construction. Performance testing is expected to commence in late 2013 and the facility is expected to be fully operational in 2014.

The Texas Clean Energy Project, a 400 MW IGCC facility located near Odessa, Texas will capture 90 percent of its CO_2, which is approximately 3 million metric tons annually. The captured CO_2 will be used for EOR in the West Texas Permian Basin. Additionally, the plant will produce urea and smaller quantities of commercial-grade sulfuric acid, argon, and inert slag, all of which will also be marketed. The developer expects financing to be fully arranged in 2013.

There are other CCS projects—domestic and worldwide—that are helping to further develop the CCS technology. They are noted in the DOE/NETL's Carbon Capture, Utilization, and Storage (CCUS) Database.[222] The database includes active, proposed, canceled, and terminated CCUS projects worldwide.

F. Costs

As noted, according to the D.C. Circuit case law, control costs are considered acceptable as long as they are reasonable, meaning that they can be accommodated by the industry.[223] To determine reasonableness, the Court has looked to the amount of the control costs, whether they could be passed on to the consumer, and how much they would lead prices to increase. As we discuss below, where EOR opportunities are available, the sale of captured CO_2 offers the opportunity to defray much of the costs. However, we recognize that there are places where opportunities to sell captured CO_2 for utilization in EOR operations may not be presently available. Nevertheless, as discussed below, our analysis shows that this cost structure—with and without EOR—is consistent with the D.C. Circuit's criteria for determining that costs are reasonable.

At the outset, it should be noted that even though the costs of coal-fired electricity generation—even when not incorporating CCS technology—are high when compared to the current costs of new NGCC generation, some utilities and other project developers have indicated a willingness to proceed with new fossil fuel-fired boilers and IGCC units. They have indicated the need for energy and fuel diversity. They have also indicated a skepticism regarding long-term projections for low natural gas prices and high availability. And there may be other reasons why developers have indicated a willingness to build new coal-fired plants, even if they currently do not appear to be the most economic choice.

1. Cost Estimates for Implementation of Partial CCS

The EPA has examined costs of new fossil fueled power generation options. These options are shown in Table 6 below. The costs in Table 6 are projected for new fossil generation with and without various carbon capture options. The costs for new NGCC technology are provided at two different natural gas prices: at $6.11/MMBtu, which is reasonably consistent with current and projected prices; and at $10/MMBtu, which would be well above current and projected natural gas prices. We also show projected costs for SCPC and IGCC units with no CCS (i.e., units that would not meet the proposed emission standard) and for those units with partial capture CCS installed such that their emissions would meet the proposed 1,100 lb CO_2/MWh standard. We have also included costs for those same units when EOR opportunities are available. We have included a ''low EOR'' case assuming a low EOR price of $20 per ton of CO_2, and a ''high EOR'' of $40/ton. These EOR prices are net of the costs of transportation, storage, and monitoring (TSM). We also show the projected costs for implementation of full capture CCS (i.e., 90 percent capture).

[221] In cooperation with the U.S. Department of Energy (DOE), the FutureGen 2.0 project partners will upgrade a power plant in Meredosia, IL with oxy-combustion technology to capture approximately more than 90 percent of the plant's carbon emissions. *http://www.futuregenalliance.org/.*

[222] Available at *http://www.netl.doe.gov/technologies/carbon_seq/global/database/.*

Information in the database regarding technologies being developed for capture, evaluation of sites for carbon dioxide (CO_2) storage, estimation of project costs, and anticipated dates of completion is sourced from publically available information. The CCUS Database provides the public with information regarding efforts by various industries, public groups, and governments towards development and eventual deployment of CCUS technology.

[223] In addition, the EPA may consider costs through a national lens, as discussed below.

TABLE 6—LEVELIZED COST OF ELECTRICITY FOR FOSSIL FUEL ELECTRIC GENERATING TECHNOLOGIES, EXCLUDING TRANSMISSION COSTS [224] [225]

Technology	Levelized cost of electricity ($2011/MWh)
NGCC @ $6.11/MMBtu	59
NGCC @ $10.0/MMBtu	86
SCPC w/o CCS [226]	92
SCPC (1,100 lb/MWh; no EOR)	110
SCPC (1,100 lb/MWh; low EOR)	96
SCPC (1,100 lb/MWh; high EOR)	88
SCPC (full, 90 percent CCS)	147
IGCC w/o CCS	97
IGCC (1,100 lb/MWh; no EOR)	109
IGCC (1,100 lb/MWh; low EOR)	101
IGCC (1,100 lb/MWh; high EOR)	97
IGCC (full, 90 percent CCS)	136

The DOE/NETL reports cite an accuracy range of −15% to +30% for the central point estimates shown in Table 6, which are based on a number of assumptions, including: an EPCM [227] contracting methodology, ISO ambient conditions, Midwest merit-shop labor costs, and a level greenfield site in the United States Midwest with no unusual characteristics (e.g., flood plain, seismic zones, environmental remediation). For specific sites that differ from this generic description, plant costs could differ from the quoted range. We have presented that central estimate above. Also note that the 2010 DOE/NETL capital and operating costs and coal price were updated to 2011 dollars using the values from the 2012 DOE/NETL report. The value of the DOE/NETL studies lies not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.

For an emerging technology like CCS, costs can be estimated for a ''first-of-a-kind'' (FOAK) plant or an ''nth-of-a-kind'' (NOAK) plant, the latter of which has lower costs due to the ''learning by doing'' and risk reduction benefits that result from serial deployments as well as from continuing research, development and demonstration projects.[228] The estimates provided in Table 6 for a new NGCC unit and for a SCPC plant without CO_2 capture are based on mature technologies and are thus NOAK costs. For plants that utilize technologies that are not yet fully mature and/or which have not yet been serially deployed in a commercial context, such as IGCC or any plant that includes CO_2 capture, the cost estimates in Table 6 represent a plant that is somewhere between FOAK and NOAK, sometimes referred to as ''next-of-a-kind'', or ''next commercial offering''. These cost estimates for next commercial offerings do not include the unique cost premiums associated with FOAK plants that must demonstrate emerging technologies and iteratively improve upon initial plant designs. However, these costs do utilize currently available cost bases for emerging technologies with associated process contingencies applied at the appropriate subsystem levels. It should also be noted that successful RD&D can lead to improved performance and lower costs.

Because there are a number of projects currently under development, the EPA believes it is reasonable to focus on the next-of-a-kind costs provided in Table 6. The lessons learned from design, construction and operation of those projects, as well as for that of Duke Energy's Edwardsport IGCC (which does not include CCS) will help lower costs for future gasification facilities implementing CCS. The TCEP project and the HECA project are both in advanced stages of design and development. Summit Power, the developer of TCEP, is also pursuing a number of additional projects that would benefit from lessons learned from TCEP. These include the Captain Clean Energy Project in the United Kingdom (UK) and another poly-generation project in Texas.[229] For a new conventional PC plant implementing post-combustion CCS, the Boundary Dam project will perhaps represent a FOAK project while the W.A. Parish project may represent a second-of-a-kind project—or perhaps even a next-of-a-kind project.

Further, as discussed elsewhere in this preamble, many of the individual components of a new generation project with CCS have been previously demonstrated. For example, capturing CO_2 from a coal gasification syngas stream has been occurring for more than ten years at the Dakota Gasification facility. Experience gained at that facility can inform design and operational choices of a new IGCC implementing partial CCS.

For all these reasons, the next IGCC and SCPC facilities with CCS can be expected to be less expensive than the current FOAK projects, but more expensive than the NOAK facilities with CCS that construct when CCS has become a fully mature technology. The costs in Table 6 reflect those next-of-a-kind costs.

The EPA has also examined costs of new non-fossil fueled power generation options. These options are shown in Table 7 below.

[224] These costs are derived from the following DOE/NETL studies: (1) Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity, Rev 2, DOE/NETL–2010/1397 (Nov 2010); (2) Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases'' DOE/NETL–341/082312 (Aug 2012); (3) Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture, DOE/NETL–2011/1498 (May 2011). Capacity factor are assumed at 85 percent.

[225] These costs do not include the impact of subsidies that may potentially be available to developers of new projects that include CCS.

[226] SCPC LCOE includes a 3 percent increase to the weighted average cost of capital to reflect EIA's climate uncertainty adder (CUA).

[227] Engineering, Procurement, and Construction Management.

[228] Elsewhere in this preamble, we describe the evidence that as technology matures, its costs decrease. Note also that EPA regulations of mobile source air emissions incorporate the decreasing costs of technology over time. See, e.g., ''2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards—Final Rule,'' 77 Fed. Reg. 62624, 62984/1 to 62985/1 (October 15, 2012) (incorporating ''cost reductions, due to learning effects'').

[229] *http://ghgnews.com/index.cfm/summit-even-without-uk-demo-funding-project-will-move-forward/?mobileFormat=true.*

TABLE 7—RANGE OF LEVELIZED COST OF ELECTRICITY FOR NON-FOSSIL FUEL ELECTRIC GENERATING TECHNOLOGIES, EXCLUDING TRANSMISSION COSTS [230] [231]

Technology	Levelized cost of electricity ($2011/MWh)
Nuclear	103–114
Biomass	97–130
Geothermal	80–99
Combustion Turbine	87–116
Onshore Wind	70–97
Offshore Wind	177–289
Solar PV [232]	109–220
Solar Thermal	184–412
Nuclear	103–114
Biomass	97–130
Geothermal	80–99

It is important to note here that both the EIA and the EPA apply a climate uncertainty adder (CUA)—represented by a three percent increase to the weighted average cost of capital—to certain coal-fired capacity types. The EIA developed the CUA to address the disconnect between power sector modeling absent GHG regulation and the widespread use of a cost of CO_2 emissions in power sector resource planning.

The CUA reflects the additional planning cost typically assigned by project developers and utilities to GHG-intensive projects in a context of climate uncertainty. The EPA believes the CUA is consistent with the industry's planning and evaluation framework (demonstrable through IRPs and PUC orders) and is therefore necessary to adopt in evaluating the cost competitiveness of alternative generating technologies.

EPA believes the CUA is relevant in considering the range of costs that power companies are willing to pay for generation alternatives to natural gas. To the extent that a handful of project developers are still considering coal without CCS, EPA believes, based both on the analysis the EIA undertook in developing the CUA approach and the EPA's review of IRPs,[233] they must fall into one of two classes. The first, which is the minority, is not factoring in any form of a CUA. The second, which is the majority, assume that coal-fired power plants without CCS entail additional costs due to the risk of future regulation of CO_2. Factoring in risk associated with CO_2 suggests that these companies are, in fact, willing to pay the higher cost for coal without CCS (even if they are not actually incurring those costs today). For these reasons, EPA believes that it is appropriate to consider the cost of coal without CCS to include the CUA in the range of costs that utilities are willing to pay for alternatives to natural gas.

The EPA is requesting comment on all aspects of the CUA, including its magnitude and technology-specific application, to ensure that the EPA's supporting analysis best reflects the current standards and practices of the power sector's long-term planning process.

2. Comparison With the Costs of Other New Power Generation Options

As Tables 6 and 7 above show, while new coal-fired generation that includes CCS is more expensive than either new coal-fired generation without CCS or new NGCC generation, it is competitive with new nuclear power, which, besides natural gas combustion turbines, is the principal other option often considered for providing new base load power. It is also competitive with biomass-fired generation, which is another generation technology often considered for base load power.[234] A review of utility IRPs shows that a number of companies are considering new nuclear power as an option for new base load generation capacity in lieu of new coal-fired generation with or without CCS, because, according to the IRPs, nuclear power is a cost-effective way to generate base load electricity that addresses risks associated with potential future carbon liabilities. New fossil fuel-fired generation that includes CCS serves the same basic function as new nuclear power: providing base load power with a lower carbon footprint. New coal-fired generation that incorporates partial CCS that is sufficient to meet the CO_2 emission limitation that we are proposing in today's action (1,100 lb CO_2/MWh) would have a similar levelized cost of electricity (LCOE) as a new nuclear power plant (about $103/MWh–$114/MWh). This indicates that, at the proposed emission limitation of 1,100 lb CO_2/MWh, the cost of new coal-fired generation that includes CCS is reasonable today.

3. Costs of ''Full Capture'' CCS

As noted in Table 6, above, and discussed in the RIA [235] for this rulemaking, implementation of CCS to achieve 90 percent CO_2 capture adds considerably to the LCOE from a new SCPC or IGCC unit. The LCOE for a new SCPC and a new IGCC, both without CCS, are estimated to be $92/MWh and $97/MWh, respectively. The corresponding costs with implementation of ''full capture'' CCS are $147/MWh for the new SCPC unit and $136/MWh for the new IGCC unit. These costs exceed what project developers have been willing to pay for other low GHG-emitting base load generating technologies (e.g., nuclear) that also provide energy diversity. For that reason alone, we do not believe that the costs of full implementation of CCS are reasonable at this time.

4. Reasonableness of Costs of Partial CCS

As noted, the current costs of coal, natural gas, and construction of coal-fired or natural gas-fired EGUs have led to little currently announced or projected new coal-fired generating capacity. This very likely reflects the large price differential between the cost of a new NGCC (cost of electricity: $59/MWh at a natural gas price of $6.11/MMBtu) and SCPC without CCS (cost of electricity: $92/MWh) and IGCC without CCS (cost of electricity: $97/MWh), coupled with a leveling of demand for electricity and the recent increase in renewable sources.

We observe that most of the industry appears to take the view that the price of natural gas will remain sufficiently low for at least a long enough period into the future that new natural-gas fired electricity generation will be less expensive than new coal-fired generation. As a result, in most cases, customers or utilities that contract for

[230] Data for non-fossil fuel-fired generation comes from DOE Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2013. Levelized Cost of Electricity (LCOE) estimates come from *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm*. To maintain consistency with DOE/NETL estimates in Table 6, the EIA estimates provided in this table do not include transmission investment.

[231] The LCOE estimates in Table 7 are presented as a range that reflects EIA's view on the regional variation in local labor markets, cost and availability of fuel, and renewable resources. The capacity factor ranges for renewable non-dispatchable technologies are as follows: Wind—30 to 39 percent, Wind Offshore—33 to 42 percent, Solar PV—22 to 32 percent, and Solar Thermal—11 to 26 percent. Capacity factors for dispatchable non-fossil fueled technologies are as follows: Nuclear—90 percent, Biomass—83 percent, and Geothermal—92 percent. There is no capacity credit provided to dispatchable resources.

[232] Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[233] See Technical Support Document: ''Review of Electric Utility Integrated Resource Plans'' (Docket EPA–HQ–OAR–2013–0495).

[234] Although geothermal energy is also generally considered for base load power, it is limited in availability. The other low-GHG emitting generation listed in Table 4—solar and wind—are not used for base load.

[235] Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New Fossil Fuel-Fired Electric Utility Steam Generating Units and Stationary Combustion Turbines (available in the rulemaking docket EPA–HQ–OAR–2013–0495).

new generation are doing so for natural gas-fired generation. Long-term contracts for electricity supply are commonly for a 25-year period; thus, most of the industry appears to consider contracting for new natural gas-fired generation for a 25-year period to be the most economical of their choices.

As shown in Table 6, we estimate that a new SCPC plant costs $92/MWh, which is $33/MWh, or about 56 percent higher than the new NGCC cost of $59/MWh. Limiting the emission rate to 1,100 lb CO_2/MWh (which can be achieved by adding partial CCS), without sale of captured CO_2 for EOR, would add another $18/MWh to the cost of electricity, for a total of $110/MWh. Thus, the total additional cost to meet the proposed standard by implementing partial capture CCS (without revenues from CO_2 sales for EOR) is about half the additional cost of coal-fired generation, compared to natural-gas fired generation.

We are aware of another segment of the industry, which includes electricity suppliers who have indicated a preference for new coal-fired generation to establish or maintain fuel diversity in their generation portfolio because their customers have expressed a willingness to pay a premium for that diversity. It appears these utilities and project developers see lower risks to long-term reliance on coal-fired generation and greater risks to long-term reliance on natural gas-fired generation, compared to the rest of the industry.

We consider the costs of CCS to be reasonable for this segment of the industry as well. The additional costs of CCS for new SCPC of $18/MWh LCOE ($110/MWh for SCPC with partial CCS compared to $92/MWh for SCPC without CCS) are only about half as much as the additional costs that are already needed to be incurred to develop coal-fired electricity as compared to new NGCC generation ($92/MWh for SCPC without CCS compared to $59 MWh for NGCC at a natural gas price of $6.11/MMBtu). Moreover, it is possible that under these circumstances, the demand for the electricity would be inelastic with respect to the price because it may not depend on cost as much as on a demand for energy diversity. These circumstances would be similar to the *Portland Cement* (1975) case, discussed above, in which the D.C. Circuit upheld NSPS controls that increased capital and operating costs by a substantial percentage because the demand for the goods was inelastic with respect to price, so that the industry could pass along the costs.[236]

In addition, we consider the costs of partial CCS to be reasonable because a segment of the industry is already accommodating them. As noted, a segment of the industry consists of the several coal-fired EGU projects that already incorporate at least partial CCS. These projects, which are each progressing, include Kemper, TCEP, and HECA. Each is an IGCC plant that expects to generate profits from the sale of products that result from coal gasification, in addition to the sale of electricity. It is true that each of these projects has received DOE grants to encourage the development of CCS technology, but we do not consider such government subsidies to mean that the costs of CCS would otherwise be unreasonable. As we noted in the original proposal for this rulemaking,[237] many types of electricity generation receive government subsidies. For example, nuclear power is the beneficiary of the Price-Anderson Act, which partially indemnifies nuclear power plants against liability claims arising from nuclear incidents,[238] and domestic oil and gas production,[239] coal exploration and development,[240] and renewable energy generation [241] are each the beneficiary of Federal tax incentives.

5. Opportunities to Further Reduce the Costs of Partial CCS

a. Enhanced Oil Recovery

While the reasons noted above are sufficient to justify the reasonableness of the costs of partial CCS, in most cases, we believe that the actual costs will be less. One reason is the availability of EOR. As noted, EOR is being actively used in various counties in the U.S., and CO_2 pipelines extend into those counties from, in some cases, hundreds of miles away. We consider areas in close proximity to active EOR locations, including the pipelines that extend into those locations, to be places where EOR is available.

We recognize that, at present, certain locations are far enough away from either oilfields with EOR availability or pipelines to those oil fields that any coal-fired power plants that build in those locations would incur costs to build pipeline extensions that may render EOR non-economical. Those locations are relatively limited when legal or practical limits on building coal-fired power plants are taken into account. For example, some states with locations that are not located near EOR availability are not expected to have new coal-fired builds without CCS in any event, for legal or practical reasons. A number of States, at least in the short term, already have high reserve margins and/or have large renewable targets which push new decisions towards renewables and quick starting natural gas to provide backup to renewables over coal-fired generation.

In addition, it is important to note that coal-fired power plants that build in any particular location may serve demand in a wide area. There are many examples where coal-fired power generated in one state is used to supply electricity in other states. For instance, historically, nearly 40 percent of the power for the City of Los Angeles was provided from two coal-fired power plants located in Arizona and Utah. In another example, Idaho Power, which serves customers in Idaho and Eastern Oregon, meets its demand in part from coal-fired power plants located in Wyoming and Nevada.

As a result, the geographic scope of areas in which EOR is available to defray the costs of CCS should be considered to be large. The costs provided in Table 6 show how the ability to sell CO_2 for utilization in EOR can significantly affect the overall costs of the project.

We also considered how the opportunity to sell captured CO_2 for EOR may affect the costs for new units implementing full capture CCS. We previously indicated that the costs—$147/MWh for the new SCPC unit and $136/MWh for the new IGCC unit—are not reasonable and we rejected that option as BSER on that basis. We estimated that the SCPC with full capture LCOE could be reduced to between $93 and $115/MWh (depending on selling price of the CO_2) and the IGCC with full capture could be reduced between $91 and $109/MWh (again, depending upon the selling price of the CO_2). These costs are similar with the reasonable costs for partial capture similar units with no opportunity to sell captured CO_2 for EOR. This indicates that in some cases (Summit's TCEP, for example), developers may determine that a new unit with full capture is economically viable. However, this factor alone does not lead us to conclude that full capture CCS should be BSER. When considered in

[236] *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975).

[237] 77 FR 22418/3.

[238] *See Duke Power Co.* v. *Carolina Environmental Study Group,* 438 U.S. 59 (1978).

[239] See Internal Revenue Code section 263.

[240] See ''General Explanations of the Administration's Fiscal Year 2013 Revenue Proposals,'' pp. 120–24. *http://www.treasury.gov/resource-center/tax-policy/Documents/General-Explanations-FY2013.pdf.*

[241] *See* Internal Revenue Code section 45.

conjunction with other factors, such as the cost of full CCS where EOR is not available and the fact that more projects using partial CCS than full CCS are underway, the EPA believes that partial CCS should be considered BSER.

b. Government Subsidies

In some instances, the costs of CCS can be defrayed by grants or other benefits provided by the DOE or the states. Although, for the reasons noted earlier, we consider the current costs of partial-capture CCS even without subsidization to be reasonable, the availability of these governmental subsidies supports the reasonableness of the costs.

The 2010 Interagency Task Force Report on CCS report described the DOE program as follows:

> The DOE is currently pursuing multiple demonstration projects using $3.4 billion of available budgetary resources from the American Recovery and Reinvestment Act in addition to prior year appropriations. Up to ten integrated CCS demonstration projects supported by DOE are intended to begin operation by 2016 in the United States. These demonstrations will integrate current CCS technologies with commercial-scale power and industrial plants to prove that they can be permitted and operated safely and reliably. New power plant applications will focus on integrating pre-combustion CO_2 capture, transport, and storage with IGCC technology. Power plant retrofit and industrial applications will demonstrate integrated post-combustion capture.[242]

DOE allocated some $3.4 billion for 5–10 projects, and has committed $2.2 billion for 5 projects to date. In addition, various other federal and state incentives are also available to many projects. The 2010 Interagency Task Force on CCS, in surveying all of the federal and state benefits available, concluded that the DOE grants, ''plus . . . federal loan guarantees, tax incentives, and state-level drivers, cover a large group of potential CCS options.'' [243]

In addition, regulatory programs may serve to defray the costs of CCS, including, for example, Clean Energy Standards or guaranteed electricity purchase price agreements.[244]

As noted above and in the April 2012 proposal, the need for subsidies to support emerging energy systems and new control technologies is not unusual. Each of the major types of energy used to generate electricity has been or is currently being supported by some type of government subsidy such as tax benefits, loan guarantees, low-cost leases, or direct expenditures for some aspect of development and utilization, ranging from exploration to control installation. This is true for fossil fuel-fired; as well as nuclear-, geothermal-, wind-, and solar-generated electricity.[245]

c. Expected Reductions in the Costs of CCS

The EPA reasonably projects that the costs of CCS will decrease over time as the technology becomes more widely used. Although, for the reasons noted earlier, we consider the current costs of CCS to be reasonable, the projected decrease in those costs further supports their reasonableness. The D.C. Circuit case law that authorizes determining the ''best'' available technology on the basis of reasonable future projections supports taking into account projected cost reductions as a way to support the reasonableness of the costs.

As noted above, the D.C. Circuit, in the 1973 *Portland Cement Ass'n* v. *Ruckelshaus* case, stated that the EPA, in identifying the ''best system of emission reduction . . . adequately demonstrated,'' may ''look[ ] toward what may fairly be projected for the regulated future, rather than the state of the art at present. . . .'' [246] In the 1999 *Lignite Energy Council* v. *EPA* case, the Court elaborated:

> Of course, where data are unavailable, EPA may not base its determination that a technology is adequately demonstrated or that a standard is achievable on mere speculation or conjecture . . . but EPA may compensate for a shortage of data through the use of other qualitative methods, including the reasonable extrapolation of a technology's performance in other industries.[247]

It is logical to read these statements in the D.C. Circuit case law to apply as well to the cost component of the ''best system of emission reduction . . . adequately demonstrated.''

We expect the costs of CCS technologies to decrease for several reasons. We expect that significant additional knowledge will be gained from deployment and operation of at least two new coal-fired generation projects that include CCS. These projects are the Southern Company's Kemper County Energy Facility IGCC with CCS and the Boundary Dam CCS project on a conventional coal-fired power plant in Canada. They are currently under construction and are expected to commence operation next year. In addition there are several other CCS projects in advanced stages of development in the U.S. (e.g., the Texas Clean Energy Project, the Hydrogen Energy California Project, and the Future Gen project in Illinois) that may also provide additional information. In addition, research is underway to reduce CO_2 capture costs and to improve performance. The DOE/NETL sponsors an extensive research, development and demonstration program that is focused on developing advanced technology options designed to dramatically lower the cost of capturing CO_2 from fossil-fuel energy plants compared to today's available capture technologies. The DOE/NETL estimates that using today's available CCS technologies would add significantly to the cost of electricity for a new pulverized coal plant, and the cost of electricity for a new advanced gasification-based plant would be increased by approximately half of the increase at a comparable PC facility. (Note that these cost increases would be less for the partial capture standard being proposed in today's document.) The CCS research, development and demonstration program is aggressively pursuing efforts to reduce these costs to a less than 30 percent increase in the cost of electricity for PC power plants and a less than 10 percent increase in the cost of electricity for new gasification-based power plants.[248] The large-scale CO_2 capture demonstrations that are currently planned and in some cases underway, under the DOE's initiatives, as well as other domestic and international projects, will generate operational knowledge and enable continued commercialization and deployment of these technologies.

Gas absorption processes using chemical solvents, such as amines, to separate CO_2 from other gases have been in use since the 1930s in the natural gas industry and to produce food and chemical grade CO_2. The advancement of amine-based solvents is an example of technology development that has improved the cost and performance of CO_2 capture. Most single component amine systems are not practical in a flue

[242] Task Force Report on CCS, p. 76

[243] Task Force Report on CCS, p. 76

[244] See Center for Climate and Energy Solutions, ''Financial Incentives for CCS''—available at *http://www.c2es.org/*.

[245] 77 FR 22418/3.

[246] *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 391 (D.C. Cir. 1973), *quoted in Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933–34 (D.C. Cir. 1999).

[247] *Lignite Energy Council* v. *EPA,* 198 F.3d 930, 934 (D.C. Cir. 1999). Based on this view that EPA may extrapolate from other industries, the Court in the *Lignite Energy Council* v. *EPA* case upheld a control technology as being ''adequately demonstrated'' for coal-fired industrial boilers because the technology was utilized by utility boilers.

[248] DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap, U.S. Department of Energy National Energy Technology Laboratory, December 2010.

gas environment as the amine will rapidly degrade in the presence of oxygen and other contaminants. The Fluor Econamine FG[SM] process uses a monoethanolamine (MEA) formulation specially designed to recover CO_2 and contains a corrosion inhibitor that allows the use of less expensive, conventional materials of construction. Other commercially available processes use sterically hindered amine formulations (for example, the Mitsubishi Heavy Industries KS–1 solvent) which are less susceptible to degradation and corrosion issues. The DOE/NETL and private industry are continuing to sponsor research on advanced solvents (including new classes of amines) to improve the CO_2 capture performance and reduce costs.

Significant reductions in the cost of CO_2 capture would be consistent with overall experience with the cost of pollution control technology. A significant body of literature suggests that the per-unit cost of producing or using a given technology declines as experience with that technology increases over time,[249] and this has certainly been the case with air pollution control technologies. Reductions in the cost of air pollution control technologies as a result of learning-by-doing, reductions in financial premiums related to risk, research and development investments, and other factors have been observed over the decades.

In addition, we note that the 2010 Interagency Task Force on CCS report recognized that CCS would not become more widely available without a regulatory framework that promoted CCS or a strong price signal for CO_2. Today's action is an important component in developing that framework.

G. Promotion of Technology

It is clear that identifying partial CCS as the BSER promotes the utilization of CCS because any new fossil fuel-fired utility boiler or IGCC unit will need to install partial capture CCS in order to meet the emission standard. Particularly because the technology is relatively new, additional utilization is expected to result in improvements in the performance technology and in cost reductions. Moreover, identifying partial capture CCS as the BSER will encourage continued research and development efforts, such as those sponsored by the DOE/NETL. In contrast, not identifying partial CCS as the BSER could potentially impede further utilization and development of CCS. It is important to promote deployment and further development of CCS technologies because they are the only technologies that are currently available or are expected to be available in the foreseeable future that can make meaningful reductions in CO_2 emissions from fossil fuel-fired utility boilers and IGCC units.

Identifying partial CCS as the BSER also promotes further use of EOR because, as a practical matter, we expect that new fossil fuel-fired EGUs that install CCS will generally make the captured CO_2 available for use in EOR operations. The use of EOR lowers costs for production of domestic oil, which promotes the important goal of energy independence.

H. Nationwide, Longer-Term Perspective

As noted, the D.C. Circuit in *Sierra Club* held:

> The language of [the definition of ''standard of performance'' in] section 111 . . . gives EPA authority when determining the best . . . system to weigh cost, energy, and environmental impacts in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present.[250]

Considering on ''the national and regional levels and over time'' the criteria that go into determining the ''best system of emission reduction . . . adequately demonstrated'' also supports identifying partial CCS as that best system because doing so would not have adverse impacts on the power sector, national electricity prices, or the energy sector.

1. Structure of the Power Sector

Identifying partial CCS as the BSER for new fossil fuel-fired utility boilers and IGCC units is consistent with the current and projected future structure of the power sector. As noted, we project that in light of the current and projected trends in coal and natural gas costs, virtually all new electric generating capacity will employ NGCC technology or renewable energy, and very little new capacity will be coal-fired.

As noted above, the recent history of solid fossil fuel-fired projects suggest that these new coal-fired builds, if they occur, may (i) consist of an IGCC unit, including features such as sale of additional byproducts (e.g., plants such as the Texas Clean Energy Project, which intends to manufacture fertilizer products for sale and sell captured CO_2 for EOR in addition to selling electricity), use of lower cost opportunity fuels (such as petcoke proposed to be used at the Hydrogen Energy California facility) and/or rely on additional local regulatory drivers (such as California's AB–32 program which incentivizes lower CO_2 generating technologies), all of which would be designed to offset enough of the additional coal-related costs to be able to compete with natural-gas fired electricity in the marketplace; and (ii) be designed to offer fuel diversity to a group of customers that are willing to pay a premium in electricity prices (such as the Power4Georgians project in Washington County, Georgia).

Projects in the first category would by definition already include at least partial CCS and, as a result, would be affected by this rule to only a limited extent. Projects in the second category would be more affected, but developers of these projects would nevertheless have several options. They could pursue coal with CCS and possibly rely on cost savings from EOR or on their customers' willingness to pay a higher premium. Alternatively, they could choose a different generation technology (most likely natural gas). Even if they chose a different generation technology, the small number of these sources and the fact that the basic demand for electricity would still be met would limit the impact of this rule on the power sector.

2. Impacts on Nationwide Electricity Prices

Identifying partial CCS as the BSER for 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 partial CCS will, on a nationwide basis, be small because no more than a few new coal-fired projects are expected, and because, as noted, at least some of these can be expected to incorporate CCS technology in any event. It should be noted that the computerized model the EPA relies on to assess energy sector and nationwide impacts—the Integrated Planing Model (IPM)—does not forecast any new coal-fired EGUs through 2020. Based on these IPM analyses, the RIA for this

[249] These studies include: John M. Dutton and Annie Thomas, ''Treating Progress Functions as a Managerial Opportunity,'' Academy of Management review, 1984, vol. 9, No. 2, 235–247; Dennis Epple, Linda Argote, and Rukmini Devadas, ''Organizational Learning Curves: A Method for Investigating Intra-plant Transfer of Knowledge Acquired Through Learning by Doing,'' Organizational Science, Vol. 2, No. 1 (February 1991); International Energy Agency, Experience Curves for Energy Technology Policy (2000); and Paul L. Joskow and Nancy L. Rose, ''The Effects of Technological Change, Experience, and Environmental Regulation on the Construction Cost of Coal-Burning Generating Units,'' RAND Journal of Economics, Vol. 16, Issue 1, 1–27 (1985). See discussion in ''The Benefits and Costs of the Clean Air Act from 1990 to 2020,'' U.S. EPA, Office of Air and Radiation (April 2011).

[250] *Sierra Club* v. *Costle,* 657 F.2d at 330.

rulemaking concludes that the proposed standard of 1,100 lb of CO_2/MWh for new fossil fuel-fired EGUs, which is based on partial CCS as the best demonstrated system, does not create any costs.

3. Energy Considerations

Identifying partial CCS as the BSER for new fossil fuel-fired utility boilers and IGCC units is consistent with nationwide energy considerations because it will not have adverse effects on the structure of the power sector, will promote fuel diversity over the long term, and will not have adverse effects on the supply of electricity.

Identifying partial CCS as the BSER will not have adverse impacts on the structure of the power sector because, as noted, for reasons related to the cost differential between natural gas-fired and coal-fired electricity, very little, if any, new coal-fired EGUs are projected to be built, and at least some of those that may be built would be expected to include CCS technology in any event.

In addition, identifying partial CCS as the BSER for coal will be beneficial to coal-fired electric generation, and therefore fuel diversity, over the long term. This is because identifying partial CCS as BSER eliminates uncertainty as to future control obligations for coal-fired capacity. Currently, any new coal-fired source that constructs without CCS faces the risk that future state or federal controls may require carbon capture, which would require the source to retrofit to CCS, which, in turn, is a more expensive proposition. This risk is heightened because power plants have expected lives of 30 to 40 years and the likelihood of future carbon limitations can be expected to remain throughout that period. Any new coal-fired source that constructs with partial-capture CCS will achieve some level of CO_2 emissions reductions, which lowers the risk of future liability, and may provide competitive advantages over higher emitting sources. Because at present, new electric generating construction is primarily natural gas-fired, benefiting new coal-fired capacity, at least over the long term, protects fuel diversity.

Moreover, even if requiring CCS adds sufficient costs to prevent a new coal-fired plant from constructing in a particular part of the country due to lack of available EOR to defray the costs, or, in fact, from constructing at all, a new NGCC plant can be built to serve the electricity demand that the coal-fired plant would otherwise serve. Thus, the present rulemaking does not prevent basic electricity demand from being met, and thus does not have an adverse effect on the supply of electricity. As noted above, the EPA is authorized to promulgate standards of performance under CAA section 111 that may have the effect of precluding construction of sources in certain geographic locations.

4. Environmental Considerations

Identifying partial CCS as the BSER for coal-fired power plants protects the environment by preventing large amounts of CO_2 emissions from new fossil fuel-fired utility boilers and IGCC units. As noted, CCS is the only technology available at present or within the foreseeable future that provides meaningful reductions in the amount of CO_2 emissions in this sector.

I. Deference

As noted above, the D.C. Circuit has held that it will grant a high degree of deference to the EPA in determining the appropriate standard of performance. Because determining the BSER for coal-fired power plants requires balancing several factors, including on a nationwide basis and over time, the EPA's determination that partial CCS is the BSER should be granted a high degree of deference.

J. CCS and BSER in Locations Where Costs Are Too High To Implement CCS

As noted above, under CAA section 111, an emissions standard may meet the requirements of a ''standard of performance'' even if it cannot be met by every new source in the source category that would have constructed in the absence of that standard. As also noted above, the EPA's analysis for this proposal indicates that coal-fired power plants that would otherwise construct in the absence of the standards in this proposal may still do so.

However, we recognize that there may be some geographic locations where EOR is not practicably available, so that in those locations, the higher costs of CCS may tilt the economics against new coal-fired construction. Even in this case, the standard would remain valid under CAA section 111, particularly because the basic demand for electricity could still be served by NGCC, which this rulemaking determines to be the ''best system'' for natural gas-fired power plants.

K. Compliance Period

1. 12-Operating-Month Period

Under today's proposal, sources must meet the 1,100 lb CO_2/MWh limit on a 12-operating-month rolling basis. This 12-operating-month period is important due 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. By comparison, efficiency has a smaller impact on the emissions rate for criteria or hazardous air pollutants (HAPs). This is because control of criteria pollutants and HAPs often involves the use of a pollution control device that results in significant reductions, often greater than 90 percent. In this situation, the performance of the specific pollution control device impacts the emissions rate much more than the EGU efficiency.

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. Because the 12-operating-month rolling average can be calculated each month, this form of the standard makes it possible to assess compliance and take any needed corrective action on a monthly basis. 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.

We solicit comment on, in the alternative, basing compliance requirements on an annual (calendar year) average basis.

2. 84-Operating-Month Compliance Period

Under today's proposal, new fossil fuel-fired boilers and IGCC units will have the option to alternatively meet an emission standard on an 84-operating-month rolling basis.

The EPA has previously offered sources optional, longer-term emission standards that are stricter than the primary emissions standard in combination with a longer averaging period. We are proposing that this alternative emission limit should be between 1,000–1,050 lb CO_2/MWh and we are requesting comment on what the final numerical standard should be (within that range) such that the 84-operating-month standard would be as stringent as or more stringent than the 12-operating-month standard.

We are also requesting comment on an appropriate 12-operating-month standard that owners/operators electing to comply with the 84-operating-month standard would have to comply with. This standard would be numerically between the alternate 12-operating-month standard and an emissions rate of a coal-fired EGU without CCS (e.g., 1,800 lb CO_2/MWh). This shorter term standard would be more easily enforced and assure adequate emission reductions.

This 84-operating-month period offers increased operational flexibility and will tend to compensate for short-term emission excursions, which may especially occur at the initial startup of the facility and the CCS system.

L. Geologic Sequestration

1. Overview

We expect that for the immediate future, virtually all of the CO_2 captured at EGUs will be injected underground for long-term geologic sequestration at sites where enhanced oil recovery is also occurring. There is an existing regulatory framework for geologic sequestration and enhanced oil recovery activities. We intend to rely upon this existing framework to verify that the CO_2 captured from an affected unit is injected underground for long-term containment. More specifically, as discussed in Section III, the EPA is proposing to build from the existing GHG Reporting Program 40 CFR part 98 to track that the captured CO_2 is geologically sequestered.

In addition, we recognize that types of CO_2 storage technologies other than geologic sequestration are under development (e.g. precipitated calcium carbonate, etc). EGUs may use another type of CO_2 storage technology to meet the standard, once the EPA has approved its use, including methods for reporting, monitoring, and verifying long-term CO_2 storage. We welcome comments on an appropriate mechanism for making this determination.

2. Existing Regulatory Framework for CCS

As noted, the EPA expects that for the immediate future, captured CO_2 from affected units will be injected underground for geologic sequestration at sites where EOR is occurring. Underground injection is currently the only technology available that can accommodate the large quantities of CO_2 captured at EGUs, and EOR provides an associated economic incentive and benefit. Three solid-fuel fired EGU projects incorporating CCS—Kemper, TCEP, and HECA—all include utilization of captured CO_2 for EOR.

The EPA has promulgated, or recently proposed, several rules to protect underground sources of drinking water and track the total amount of CO_2 that is supplied to the economy and injected underground for geologic sequestration. First, the EPA's Underground Injection Control (UIC) Class VI rule, established under authority of the Safe Drinking Water Act, sets requirements to ensure that geologic sequestration wells are appropriately sited, constructed, tested, monitored, and closed in a manner that ensures protection of underground sources of drinking water.[251] The UIC Class VI regulations contain monitoring requirements to protect underground sources of drinking water, including the development of a comprehensive testing and monitoring plan. This includes testing of the mechanical integrity of the injection well, ground water monitoring, and tracking of the location of the injected CO_2 and the associated area of elevated pressure using both direct and indirect methods, as appropriate. Projects are also required to conduct extended post-injection monitoring and site care to track the location of the injected CO_2 and monitor subsurface pressures until it can be demonstrated that there is no longer a risk of endangerment to underground sources of drinking water.

UIC Class II wells inject fluids associated with oil and natural gas production and the storage of liquid hydrocarbons. Most of the injected fluid is salt water, which is brought to the surface in the process of producing (extracting) oil and gas and subsequently re-injected. In addition, other fluids, including CO_2, are injected to enhance oil and gas production. Class II regulations include site characterization, well construction, operating, monitoring, testing, reporting, financial responsibility, and closure requirements to prevent endangerment of underground sources of drinking water. Wells that inject CO_2 underground for enhanced oil or gas recovery may be permitted as UIC Class II or Class VI wells. However, the designation of the appropriate well class depends, principally, on the risks posed or changes in the risks posed to underground sources of drinking water by a specific injection operation.

Second, the GHG Reporting Program covers sources that generate electricity (40 CFR part 98, subpart D), sources that supply CO_2 to the economy (40 CFR part 98, subpart PP) and sources that inject CO_2 underground for geologic sequestration (40 CFR part 98, subpart RR). Subpart D owners or operators of facilities that contain electricity-generating units must report emissions from electricity-generating units and all other source categories located at the facility for which methods are defined in part 98.[252] Owners or operators are required to collect emission data; calculate GHG emissions; and follow the specified procedures for quality assurance, missing data, recordkeeping, and reporting.

Subpart PP provides requirements for quantifying CO_2 supplied to the economy.[253] Affected units that capture CO_2 to inject underground or supply offsite, are subject to all of the requirements under subpart PP of the GHG Reporting Program, which relates to suppliers of CO_2. Specifically, subpart PP requires facilities with production process unit(s) that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground and which meet certain applicability requirements to report the mass of CO_2 captured. CO_2 suppliers are required to

[251] *http://water.epa.gov/type/groundwater/uic/wells_sequestration.cfm.*

[252] *http://www.epa.gov/ghgreporting/reporters/subpart/d.html.*

[253] *http://www.epa.gov/ghgreporting/reporters/subpart/pp.html.*

report the annual quantity of CO_2 transferred offsite and for what end use, including geologic sequestration.

Subpart RR requires facilities meeting the source category definition (40 CFR 98.440) for any well or group of wells to report basic information on the amount of CO_2 received for injection; develop and implement an EPA-approved monitoring, reporting, and verification (MRV) plan; and report the amount of CO_2 sequestered using a mass balance approach and annual monitoring activities. The MRV plan must be submitted and approved by the EPA and revised if necessary over time according to 40 CFR 98.448(d). The subpart RR MRV plan must include five major components:

- A delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA).
- An identification and evaluation of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways in the MMA.
- A strategy for detecting and quantifying any surface leakage of CO_2 in the event leakage occurs.
- An approach for establishing the expected baselines for monitoring CO_2 surface leakage.
- A summary of considerations made to calculate site-specific variables for the mass balance equation.

More information on the MRV plan is available in the Technical Support Document for the subpart RR final rule (75 FR 75065).

If an enhanced oil and gas recovery project holds a UIC Class VI permit, it is required to report under subpart RR. If the project holds a UIC Class II permit and is injecting a CO_2 stream underground, it is not subject to subpart RR, but the owner or operator may choose to opt-in to subpart RR. Sources reporting under subpart RR, whether they are UIC Class VI or Class II well(s), must follow the same set of requirements.

As stated in the preamble to the final subpart RR rule:

> ''while requirements under the UIC program are focused on demonstrating that USDWs are not endangered as a result of CO_2 injection into the subsurface, requirements under the GHG Reporting Program through 40 CFR part 98, subpart RR will enable EPA to verify the quantity of CO_2 that is geologically sequestered and to assess the efficacy of GS as a mitigation strategy. Subpart RR achieves this by requiring facilities conducting GS to develop and implement a MRV plan to detect and quantify leakage of injected CO_2 to the surface in the event leakage occurs and to report the amount of CO_2 geologically sequestered using a mass balance approach, regardless of the class of UIC permit that a facility holds.'' (75 FR 75060)

The Internal Revenue Service relies on the existing regulatory framework to verify geologic sequestration when determining eligibility of taxpayers claiming the 45Q tax credit. As stated in the preamble to the final subpart RR rule:

> ''EPA notes that the Internal Revenue Service (IRS) published IRS Notice 2009–83 7 to provide guidance regarding eligibility for the Internal Revenue Code section 45Q credit for CO_2 sequestration, computation of the section 45Q tax credit, reporting requirements for taxpayers claiming the section 45Q tax credit, and rules regarding adequate security measures for secure GS. As clarified in the IRS guidance, taxpayers claiming the section 45Q tax credit must follow the appropriate UIC requirements. The guidance also clarifies that taxpayers claiming section 45Q tax credit must follow the MRV procedures that are being finalized under 40 CFR part 98, subpart RR in this final rule.'' (75 FR 75060)

Third, the EPA proposed a rule that would conditionally exclude CO_2 streams from the definition of hazardous waste under RCRA, where these streams are being injected for purposes of geologic sequestration, into a UIC Class VI well and meet other conditions.[254] The rationale for the rule was that any CO_2 stream that would otherwise be defined as hazardous waste, need not be managed as hazardous waste, provided it is managed under other regulatory programs that address the potential risks to human health and the environment that these materials may pose.

3. Proposal

a. Geologic Sequestration

To provide certainty and verify that CO_2 captured at an affected unit is geologically sequestered, today's action relies upon the existing regulatory framework the EPA already has in place under the GHG Reporting Program 40 CFR part 98. As discussed in the previous section, there are key subparts (i.e., subpart D, PP and RR) under 40 CFR part 98 that provide a transparent reporting and verification mechanism for EPA and the public. The EPA requires electric generating units to report CO_2 emissions under subpart D. Facilities that capture CO_2 are required to report quantities of CO_2 captured and injected on site or transferred off-site under subpart PP. Facilities that inject CO_2 underground for geologic sequestration report under subpart RR.

First, the EPA is proposing that any affected unit that employs CCS technology which captures enough CO_2 to meet the 1,100 lb/MWh standard must report, under 40 CFR part 98, subpart RR, if the captured CO_2 is injected onsite. If the captured CO_2 is sent offsite, then the facility injecting the CO_2 underground must report under 40 CFR part 98, subpart RR. As noted above, owners and operators of projects that inject CO_2 underground and that are permitted under a UIC Class VI permit are required to comply with subpart RR. The practical impact of our proposal would be that owners and operators of projects injecting CO_2 underground that are permitted under UIC Class II and that receive CO_2 captured from EGUs to meet the proposed performance standard will also be required to submit and receive approval of a subpart RR MRV plan and report under subpart RR. This proposal does not change any of the requirements to obtain or comply with a UIC permit for facilities that are subject to EPA's UIC program under the Safe Drinking Water Act.

In order to use the GHG Reporting Program to ensure that the affected unit is sending its captured CO_2 to a site reporting under subpart RR, the EPA proposes minor modifications to subpart PP, CO_2 supply. We propose that a facility capturing CO_2 from an affected unit, and therefore subject to 40 CFR part 98, subpart PP, must provide additional information in its subpart PP annual report including (1) the electronic GHG Reporting Tool identification (e-GGRT ID) of the facility with the electric generating unit from which CO_2 was captured, and (2) the e-GGRT ID(s) for, and mass of CO_2 transferred to, each geologic sequestration site reporting under subpart RR. This proposed amendment to the GHG Reporting Program provides a transparent and consistent method to track CO_2 capture and sequestration without significantly increasing burden on the affected sources. If the affected unit does not report under 40 CFR part 98, subpart PP and comply with these proposed requirements, it will be considered in noncompliance with today's proposal.

The EPA notes that compliance with the standard of 1,100 lb CO_2/MWh is determined exclusively by the tons of CO_2 captured by the emitting EGU. The tons of CO_2 sequestered by the geologic sequestration site are not part of that calculation. However, to verify that the CO_2 captured at the emitting EGU is sent to a geologic sequestration site, we are building on existing regulatory requirements under the GHG Reporting program.

[254] 76 FR 48073 (Aug. 8, 2011).

The EPA acknowledges that there can be downstream losses of CO_2 after capture, for example during transportation, injection or storage. Though a well selected and operated site is expected to contain CO_2 for the long-term, there is the potential for unanticipated leakage. The EPA expects these losses to be modest with incentives due to the market use of CO_2 as a purchased product. There remains an issue of whether the standard itself should be adjusted to reflect these downstream losses. The EPA is not proposing to do so. Moreover, the EPA wishes to encourage rather than discourage EOR using captured CO_2 since the practice makes CCS itself more economic and thus promotes use of the technology on which the proposed standard is based. See *Sierra Club* v. *Costle,* 657 F. 2d at 347 (one purpose of section 111 standards is to promote expanded use and development of technology).

We also emphasize that today's proposal does not involve regulation of any downstream recipients of captured CO_2. That is, the regulatory standard applies exclusively to the emitting EGU, not to any downstream user or recipient of the captured CO_2 (whether the captured CO_2 is sold for EOR or otherwise sequestered underground). The requirement that the emitting EGU assure that captured CO_2 is managed at an entity subject to the GHG reporting rules is thus exclusively an element of enforcement of the EGU standard. Similarly, the existing regulatory requirements applicable to geologic sequestration are not part of the proposed NSPS. The standard is a numeric value, applicable exclusively to the emitting EGU.

The approach proposed today relies on the existing GHG Reporting framework to ensure that CO_2 captured at an affected unit is transferred to a facility reporting geologic sequestration, and it does not impose any additional requirements for an affected unit to demonstrate how the captured CO_2 is transferred to a facility that is compliant with 40 CFR part 98, subpart RR. We seek comment on whether there should be such requirements and suggestions for what those might include.

b. Alternatives to Geologic Sequestration

In the development of this proposal, the EPA has identified some potential alternatives to geologic sequestration, including but not limited to CO_2 stored in precipitated calcium carbonate and certain types of cement. The EPA solicits comment on whether these and other alternatives to geologic sequestration permanently store CO_2 (so that the stack standard is assured of achieving its object—to capture CO_2 and prevent its atmospheric release) and if they are technically available for EGUs to meet the performance standard. Consideration of how these alternatives could meet the performance standard involves understanding the ultimate fate of the captured CO_2 and the degree to which the method permanently isolates the CO_2 from the atmosphere, as well as existing methodologies to verify this permanent storage. The EPA proposes that alternatives to geologic sequestration could not be used until the EPA finalizes a mechanism to demonstrate that a non-CCS technology would result in permanent storage of CO_2. The EPA believes that the number of cases where an EGU would seek to comply with the performance standard through an alternative to CCS will be very few. However, the EPA wishes to encourage development of alternatives to geologic sequestration that could help offset the cost of CO_2 capture.

c. Drafting PSD Permits for Affected Sources Using Geologic Sequestration

In most cases, sources that are subject to this NSPS will also be a major source or major modification under PSD and required to obtain a PSD permit prior to commencing construction. A permit is the legal tool used to establish all the source limitations deemed necessary by the reviewing agency during review of the permit application, and is the primary basis for enforcement of PSD requirements. A well written permit reflects the outcome of the permit review process and clearly defines what is expected of the source. The permit must be a ''stand-alone'' document that: (1) Identifies the emissions units to be regulated; (2) establishes emissions standards or other operational limits to be met; (3) specifies methods for determining compliance and/or excess emissions, including reporting and recordkeeping requirements; and (4) outlines the procedures necessary to maintain continuous compliance with the emission limits.

One of the criteria that must be met to obtain a PSD permit is that the owner or operator of the facility must demonstrate that emissions from construction or operation of the facility will not cause or contribute to air pollution in excess of ''any other applicable emissions standard or standard of performance under this chapter.'' 42 U.S.C. 7475(a)(3)(C); see also 42 U.S.C. 7410(j). Accordingly, PSD permits for EGU sources that are subject to this NSPS will need to reflect that, at a minimum, the source will meet the requirements of this NSPS. Compliance with the NSPS emissions standard is determined exclusively by evaluating emissions of CO_2 at the EGU.[255]

As noted in the ''Implications for PSD and Title V programs'' section of this preamble, some states have authority to issue PSD permits. In other cases, the EPA issues the permit. States with EPA-approved permitting programs have some discretion in making permit decisions and including the necessary conditions in the permit to ensure the enforceability of the requirements. Additionally, some states may have additional state-specific requirements (e.g., a renewable portfolio standard adopted by a state) that may affect the stringency of the emission limits for the permits issued in their states. Thus, permits for similar source types may vary from state to state depending on the permitting program of the state, and the case-specific PSD evaluation of the source under review. However, the permits for similar sources should generally contain the same basic information.

Thus, while EPA recognizes that permit conditions may vary from state to state, the EPA believes it is important to clarify the key components that should be included in a PSD permit for sources subject to the NSPS, as proposed here, and that intend to comply with the standard using geologic storage. We believe the following general condition areas of a PSD permit would adequately show that the source will not cause or contribute to air pollution in excess of this NSPS:

- A BACT emissions limit that applies to the EGU (or EGUs) at the stationary source (''EGU facility'') that does not exceed the NSPS emission limit standard using the 12-operating-month rolling average or the NSPS alternative compliance method.
- Procedures for how the EGU will demonstrate compliance with the permitted emissions limit, which, at a minimum, meet the monitoring and recordkeeping requirements defined in § 60.5355.
- A requirement that CO_2 produced by the EGU (or EGUs) is reported under Subpart PP by the permittee.
- A requirement that all CO_2 that is geologically sequestered at the site of the EGU facility is reported under subpart RR by the permittee.
- A requirement that the captured CO_2 that the permittee sends offsite of the EGU facility is transferred to an

[255] We note that the PSD program regulates CO_2 as part of the ''Greenhouse Gas'' pollutant, which includes the aggregate group of the following gases: CO_2, CH_4, N_20, SF_6, HFCs, and PFCs.

entity that is subject to the requirements of Subpart RR.

We specifically request comment on this basic framework for PSD permits that are issued for affected EGU sources that use geologic sequestration.

VIII. Rationale for Emission Standards for Natural Gas-Fired Stationary Combustion Turbines

A. Best System of Emission Reduction

The EPA evaluated several different control technology configurations as potentially representing the ''best system of emissions reductions . . . adequately demonstrated'' (BSER) for new natural gas-fired stationary combustion turbines: (i) The use of full or partial capture CCS; and two types of efficient generation without any CCS, including (ii) high efficiency simple cycle aeroderivative turbines; and (iii) natural gas combined cycle (NGCC) technology. We do not consider full or partial capture CCS to be BSER because of insufficient information to determine technical feasibility and because of adverse impact on electricity prices and the structure of the electric power sector. In addition, we do not consider simple cycle turbines to be BSER because they have a higher emission rate and a higher cost than NGCC technology. We do find NGCC technology to be the BSER because it is technically feasible and relatively inexpensive, its emission profile is acceptably low, and it would not adversely affect the structure of the electric power sector.

We note at the outset that currently, virtually all new sources in this category are using NGCC technology. That technology is considered to be the state of the art for this source category. Because, in this rulemaking, we are considering, and selecting, NGCC as the BSER for this category, as a matter of terminology, to avoid confusion, we generally refer to the affected sources as natural gas-fired combustion turbines, and not as NGCC sources.

1. Full and Partial CCS

To determine the BSER for natural-gas-fired stationary source combustion turbines, we evaluated full and partial CCS against the criteria. We propose to reject CCS technology as the BSER because we cannot conclude that it meets several of the key criteria.

First, it is not clear that full or partial capture CCS is technically feasible for this source category. There are significant differences between natural gas-fired combustion turbines and solid fossil fuel-fired EGUs that lead us to this conclusion. First, while some of these turbines are used to serve base load power demand, many cycle their operation much more frequently than coal-fired power plants. It is unclear how part-load operation and frequent startup and shutdown events would impact the efficiency and reliability of CCS. We are not aware that any of the pilot-scale CCS projects have operated in a cycling mode. Similarly, none of the larger CCS projects being constructed, or under development, are designed to operate in a cycling mode. Furthermore, the CO_2 concentration in the flue gas of a natural gas combustion turbine is much lower (usually approximately 4 volume percent) than the CO_2 concentration in the flue gas stream of a typical coal-fired plant (which is approximately 16 volume percent for a SCPC or CFB unit) or the syngas of an IGCC unit (in which CO_2 can be as high as 60 volume percent). Therefore, the overall amount of CO_2 that can be captured in a CCS project is likely lower. Finally, unlike subpart Da affected facilities, where there are full-scale plants with CCS that are currently under construction or in advanced stages of development, the EPA is aware of only one demonstration project, which is an approximately 40 MW slip stream installation on a 320 MW NGCC unit.

Additional factors that make CCS more challenging for a natural gas combustion turbine compared to coal-fired EGUs include the time it would take to complete the CCS project and the water use requirements. Requiring CCS at a natural gas combustion turbine facility would potentially delay the project more than at a coal-fired EGU. Natural gas combustion turbine facilities can be constructed in about half the time required to construct a coal-fired EGU. Therefore, the time necessary to construct the carbon capture equipment and any associated pipelines to transport the CO_2 would have a relatively larger impact on a natural gas combustion turbine than a coal-fired EGU. Natural gas combustion turbines have relatively low cooling requirements for the steam condensing cooling cycle compared to coal-fired EGUs and often use dry cooling technology. The imposition of CCS would have a larger impact on water requirements for a natural gas combustion turbine facility compared to a coal-fired EGU.

Moreover, identifying partial or full CCS as the BSER for new stationary combustion turbines would have significant adverse effects on national electricity prices, electricity supply, and the structure of the power sector. Because virtually all new fossil fuel-fired power is projected to use NGCC technology, requiring CCS would have more of an impact on the price of electricity than the few projected coal plants with CCS and the number of projects would make it difficult to implement in the short term. In addition, requiring CCS could lead some operators and developers to forego retiring older coal-fired plants and replacing them with new NGCC projects, and instead keep the older plants on line longer, which could have adverse emission impacts. Identifying CCS and BSER for combustion turbines would likely result in higher nationwide electricity prices and could adversely affect the supply of electricity, since virtually all new fossil fuel-fired power is projected to use NGCC technology.

We recognize that identifying full or partial CCS as the BSER for this source category would result in significant emissions reductions, but at present, we already consider natural gas to be a low-GHG-emitting fuel and NGCC to be a low-emitting technology. Although identifying CCS as the BSER would promote the development and implementation of emission control technology, for the reasons described, the EPA does not believe that CCS represents BSER for natural gas combustion turbines at this time.

2. Energy Efficient Generation Technology

To determine the BSER, the EPA also evaluated the use of energy efficient generation technology, including high efficiency simple cycle aeroderivative turbines.

The use of high efficiency simple cycle aeroderivative turbines does not provide emission reductions from the current state-of-the-art technology, is more expensive than the current state-of-the-art technology, and does not develop emission control technology. For these reasons, we do not consider it BSER. According to the 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, which is higher than the base load rating emission rates of 830 and 760 lb CO_2/MWh for the conventional and advanced NGCC model facilities, respectively.

In the April 2012 proposal, we identified NGCC as the BSER for this source category, and proposed a standard of 1,000 lb/MWh. We stated:

> [A] NGCC facility is the best system of emission reduction for new base load and intermediate load EGUs. To establish an appropriate, natural gas-based standard, we reviewed the emissions rate of natural gas-fired (non-CHP) combined cycle facilities

used in the power sector that commenced operation between 2006 and 2010 and that report complete generation data to EPA. Based on this analysis, nearly 95% of these facilities meet the proposed standards on an annual basis. These units represent a wide range of geographic locations (with different elevations and ambient temperatures), operational characteristics, and sizes.[256]

The same information supports our current proposal. As described above, NGCC has a lower cost of electricity than simple cycle turbines at intermediate and high capacity factors. In addition, NGCC has an emissions rate that is approximately 25 percent lower than the most efficient simple cycle facilities. Therefore, the use of a heat recovery steam generator in combination with a steam turbine to generate additional electricity is a cost effective control for intermediate and high capacity factor stationary combustion turbines. Therefore, BSER for intermediate and high capacity factor stationary combustion turbines is the use of modern high efficiency NGCC technology.

B. Determination of the Standards of Performance

Multiple commenters on the April 2012 proposal stated the proposed standard of 1,000 lb CO_2/MWh for combined cycle facilities in the April 2012 proposal was too stringent and should be increased to a minimum of 1,100 lb CO_2/MWh. Commenters explained that the increased use of renewable energy for electricity generation will require combined cycle facilities to startup, shutdown, cycle, and operate at part-load more frequently than they currently do, and that this more cyclical operation necessarily entails a higher emission rate. The commenters stated that the recent historical emissions data that the EPA relied on for the original proposal does not account for these likely operational changes. Additional reasons given justifying a higher standard include the deterioration of efficiencies over time, the need for flexibility to use distillate oil as a backup fuel, the operation of combined cycle facilities in simple cycle mode, the fact that combined cycle facilities located at high elevations and/or in locations with high ambient temperatures are less efficient, and the fact that smaller combined cycle facilities are inherently less efficient than larger facilities. On the other hand, other commenters stated that the final standard should be lower than proposed on grounds that the best performing facilities are operating below the original proposed standard. Multiple commenters also stated that the EPA should evaluate additional CEMS data to determine the appropriate standard.

In light of these comments, we have 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 this emissions data analysis is included in a technical support document in the docket for this rulemaking. These 307 NGCC units are diverse in location, age, capacity, and operating profile. Based on these data, we propose 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 less than or equal to 850 MMBtu/h 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. Large-size combustion turbines use industrial frame type combustion turbines and may use multiple pressure or steam reheat turbines in the heat recovery steam generator (HRSG) portion of a combined cycle facility. Multiple pressure HRSGs employ two or three steam drums that produce steam at multiple pressures. The availability of multiple pressure steam allows the use of a more efficient multiple pressure steam turbine, compared to a single pressure steam turbine. A steam reheat turbine is used to improve the overall efficiency of the generation of electricity. In a steam reheat turbine, steam is withdrawn after the high pressure section of the turbine and returned to the boiler for additional heating. The superheated steam is then returned to the intermediate section of the turbine, where it is further expanded to create electricity. Although HRSGs with steam reheat turbines are more expensive and complex than HRSGs without them, steam reheat turbines offer significant reductions in CO_2 emission rates. In contrast, small-size combustion turbines frequently use aeroderivative turbine engines instead of industrial frame design turbines. While there is not a strict definition for an aeroderivative turbine, at least parts of aeroderivative turbines are derived from aircraft engines. Aeroderivative and frame turbines use different combustor designs, lubrication oil systems, and bearing designs. While aeroderivative turbines are typically more expensive than industrial frame turbines, they are generally more compact, lighter, are able to start up and shut down more quickly, and handle rapid load changes more easily than industrial frame turbines. Due to their higher simple cycle efficiencies, they have traditionally been used more for peak and intermittent purposes rather than base power generation. However, combined cycle facilities based on aeroderivative combustion turbines are available. Due to the higher efficiency of the simple cycle portion of an aeroderivative turbine based combined cycle facility, the HRSG portion would contribute relatively less to the overall efficiency than a HRSG in a frame turbine based combined cycle facility. Therefore, adding a multiple steam pressure and/or a reheat steam turbine to the HRSG would be relatively more expensive to an aeroderivative turbine based combined cycle facility compared to a frame based combined cycle facility. Consequently, multiple pressure steam and reheat steam turbine HRSG are not widely available for aeroderivative turbine based combined cycle facilities. In addition, since aeroderivative turbine engines have faster start times and change load more quickly than frame turbines, aeroderivative turbine based combined cycle facilities are more likely to run at part load conditions and to potentially bypass the HRSG and run in simple cycle mode for short periods of time than industrial frame turbine based combined cycle facilities.

Because of these differences in equipment and inherent efficiencies of scale, the smaller capacity NGCC units (850 MMBtu/h and smaller) available on the market today are less efficient than the larger units (larger than 850 MMBtu/h). According to the data in the EPA's Clean Air Markets Division database, which contains information on 307 NGCC facilities, there is a 7 percent difference in average CO_2 emission rate between the small- and large-size units. This relative difference is consistent with what would be predicted when comparing the efficiency values reported in *Gas Turbine World* of small and large combined cycle designs.[257] Fourteen of the study NGCC facilities evaluated using the Clean Air Markets data have heat input rates of less than or equal to 850 MMBtu/h, and the

[256] 77 FR 22414/1.

[257] Gas Turbine World—2012 GTW Handbook.

remaining 293 are above 850 MMBtu/MWh. Two of the small combined cycle facilities had a maximum 12-operating-month rolling average emissions rate equal to or greater than 1,000 lb CO_2/MWh and one had a maximum 12-operating-month rolling average emissions rate equal to or greater than 1,100 lb CO_2/MWh. Twenty three of the large turbines had at least one occurrence of a 12-operating-month rolling average emissions rate greater than or equal to 1,000 lb CO_2/MWh and forty four had at least one occurrence of a 12-operating-month rolling average emissions rate greater than or equal to 950 lb CO_2/MWh. Therefore, because over 90 percent of small and large existing NGCC facilities are currently operating below the emission rates of 1,100 lb CO_2/MWh and 1,000 lb CO_2/MWh, respectively, these rates are considered BSER for new NGCC facilities in those respective subcategories. These values represent the emission rates that a modern high efficiency NGCC facility located in the U.S. would be able to maintain over its life.

To further evaluate the impact of the proposed rule we reviewed the GHG BACT permits for eight recently permitted NGCC facilities. Of these facilities, seven are larger than 850 MMBtu/h, and one is smaller. The seven larger facilities all have emission rates below 1,000 lb/MWh, and as low as 880 lb/MWh. The single smaller facility, which is 400 MMBtu/h, has a permitted emissions rate of 1,100 lb CO_2/MWh. The GHG BACT permit limits are higher than the base load rating emissions rates because they take into account actual operating conditions.

We are requesting comment on a range of 950 to 1,100 lb CO_2/MWh (430 to 500 kg CO_2/MWh) for the large turbine subcategory and 1,000 to 1,200 lb CO_2/MWh (450 to 540 kg CO_2/MWh) for the small turbine subcategory.

IX. Implications for PSD and Title V Programs

A. Overview

The proposal in this rulemaking would, for the first time, regulate GHGs under CAA section 111. Commenters have raised questions regarding whether this rule will have implications for regulations and permits written under the CAA PSD preconstruction permit program and the CAA Title V operating permit program.

Today's proposal should not require any additional SIP revisions to make clear that the Tailoring Rule thresholds—described below—continue to apply to the PSD program. Likewise, today's rulemaking does not have implications for the Tailoring Rule thresholds established with respect to sources subject to title V requirements. Furthermore, this proposal does not have any direct applicability on the determination of Best Available Control Technology (BACT) for existing EGUs that require PSD permits to authorize a major modification of the EGU. Finally, this proposal does have some implications for Title V fees, but EPA is proposing action to address those implications as discussed below.

B. Applicability of Tailoring Rule Thresholds Under the PSD Program

States with approved PSD programs in their state implementation plans (SIPs) implement PSD, and most of these States have recently revised their SIPs to incorporate the higher thresholds for PSD applicability to GHGs that the EPA promulgated under what we call the Tailoring Rule.[258] Commenters have queried whether under the EPA's PSD regulations, promulgation of a section 111 standard of performance for GHGs would require these states to revise their SIPs again to incorporate the Tailoring Rule thresholds again. The EPA included an interpretation in the Tailoring Rule preamble, which makes clear that the Tailoring Rule thresholds continue to apply if and when the EPA promulgates requirements under CAA section 111. Even so, in today's proposal, the EPA is including a provision in the CAA section 111 regulations that confirms this interpretation.

However, if a state with an approved PSD SIP program that applies to GHGs believes that were the EPA to finalize the rulemaking proposed today, the state would be required to revise its SIP to make clear that the Tailoring Rule thresholds continue to apply, then (i) the EPA encourages the state to do so as soon as possible, and (ii) if the State cannot do so promptly, the EPA will assess whether to proceed with a separate rulemaking action to narrow its approval of that state's SIP so as to assure that for federal purposes, the Tailoring Rule thresholds will continue to apply as of the effective date of the final rule that the EPA is proposing today.

In the alternative, if the Tailoring Rule thresholds would not continue to apply when the EPA promulgates requirements under CAA section 111, then the EPA would assess whether to proceed with a separate rulemaking action to narrow its approval of all of the State's approved SIP PSD programs to assure that for federal purposes, the Tailoring Rule thresholds will continue to apply as of the effective date of the final rule that EPA is proposing today.

Under the PSD program in part C of title I of the CAA, in areas that are classified as attainment or unclassifiable for NAAQS pollutants, a new or modified source that emits any air pollutant subject to regulation at or above specified thresholds is required to obtain a preconstruction permit. This permit assures that the source meets specified requirements, including application of BACT. States that are authorized by the EPA to administer the PSD program may issue PSD permits. If a state is not authorized, then the EPA issues the PSD permits.

Regulation of GHG emissions in the Light Duty Vehicle Rule (75 FR 25324) triggered applicability of stationary sources to regulations for GHGs under the PSD and title V provisions of the CAA. Hence, on June 3, 2010 (75 FR 31514), the EPA issued the ''Tailoring Rule,'' which establishes thresholds for GHG emissions in order to define and limit when new and modified industrial facilities must have permits under the PSD and title V programs. The rule addresses emissions of six GHGs: CO_2, CH_4, N_2O, HFCs, PFCs and SF_6. On January 2, 2011, large industrial sources, including power plants, became subject to permitting requirements for their GHG emissions if they were already required to obtain PSD or title V permits due to emissions of other (non-GHG) air pollutants.

Commenters have queried whether, because of the way that the EPA's PSD regulations are written, promulgating the rule we propose today may raise questions as to whether the EPA must revise its PSD regulations—and, by the same token, whether states must revise their SIPs—to assure that the Tailoring Rule thresholds will continue to apply to sources subject to PSD. That is, under the EPA's regulations, PSD applies to a ''major stationary source'' that undertakes construction and to a ''major modification.'' 40 CFR 51.166(a)(7)(i) and (iii). A ''major modification'' is defined as ''any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase . . . and a significant net emissions increase. . . .'' Thus, for present purposes, the key component of these

[258] ''Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule,'' 75 FR 31514 (June 3, 2010). In the Tailoring Rule, EPA established a process for phasing in PSD and Title V applicability to sources based on the amount of their GHG emissions, instead of immediately applying PSD and title V at the 100 or 250 ton per year or thresholds included under the PSD and title V applicability provisions.

applicability provisions is that PSD applies to a ''major stationary source.''

The EPA's regulations define the term ''major stationary source'' as a ''stationary source of air pollutants which emits, or has the potential to emit, 100 [or, depending on the source category, 250] tons per year or more of any regulated NSR pollutant.'' 40 CFR 51.166(b)(1)(i)(*a*). The EPA's regulations go on to define ''regulated NSR pollutant'' 40 CFR 51.166(b)(49) to include any pollutant that is subject to any standard promulgated under section 111 of the Act. Thus, the PSD regulations contain a separate PSD trigger for pollutants regulated under the NSPS, 40 CFR 51.166(b)(49)(ii) (the ''NSPS trigger provision''), so that as soon as the EPA promulgates the first NSPS for a particular air pollutant, as we are doing in this rulemaking with respect to the GHG air pollutant, then PSD is triggered for that air pollutant.

The Tailoring Rule, on the face of its regulatory provisions, incorporated the revised thresholds it promulgated into only the fourth prong (''[a]ny pollutant that otherwise is subject to regulation under the Act''), and not the NSPS trigger provision in the second prong (''[a]ny pollutant that is subject to any standard promulgated under section 111 of the Act''). For this reason, a question may arise as to whether the Tailoring Rule thresholds apply to the PSD requirement as triggered by the NSPS that the EPA is promulgating in this rulemaking.

However, although the Tailoring Rule thresholds on their face apply to only the term, ''subject to regulation'' in the definition of ''regulated NSR pollutant,'' the EPA stated in the Tailoring Rule preamble that the thresholds should be interpreted to apply to other terms in the definition of ''major stationary source'' and in the statutory provision, ''major emitting facility.'' Specifically, the EPA stated:

3. Other Mechanisms

As just described, we selected the ''subject to regulation'' mechanism because it most readily accommodated the needs of States to expeditiously revise—through interpretation or otherwise—their state rules. Even so, it is important to recognize that this mechanism has the same substantive effect as the mechanism we considered in the proposed rule, which was revising numerical thresholds in the definitions of major stationary source and major modification. Most importantly, although we are codifying the ''subject to regulation'' mechanism, that approach is driven by the needs of the states, and our action in this rulemaking should be interpreted to rely on any of several legal mechanisms to accomplish this result. Thus, our action in this rule should be understood as revising the meaning of several terms in these definitions, including: (1) The numerical thresholds, as we proposed; (2) the term, ''any source,'' which some commenters identified as the most relevant term for purposes of our proposal; (3) the term, ''any air pollutant; or (4) the term, ''subject to regulation.'' The specific choice of which of these constitutes the nominal mechanism does not have a substantive legal effect because each mechanism involves one or another of the components of the terms ''major stationary source''—which embodies the statutory term, ''major emitting facility''—and ''major modification,'' which embodies the statutory term, ''modification,'' and it is those statutory and regulatory terms that we are defining to exclude the indicated GHG-emitting sources.[Footnote]

[Footnote: We also think that this approach better clarifies our long standing practice of interpreting open-ended SIP regulations to automatically adjust for changes in the regulatory status of an air pollutant, because it appropriately assures that the Tailoring Rule applies to both the definition of ''major stationary source'' and ''regulated NSR pollutant.'']

75 FR 31582.

Thus, according to the preamble of the final Tailoring Rule, the definition of ''major stationary source'' itself already incorporates the Tailoring Rule thresholds, and not just through one component (the ''subject to regulation'' prong of the term ''regulated NSR pollutant'') of that definition. For this reason, it is the EPA's position that the Tailoring Rule thresholds continue to apply even when the EPA promulgates the first NSPS for GHGs (which, as noted above, triggers the PSD requirement under the NSPS trigger provision in the definition of ''regulated NSR pollutant'').[259]

As a result, the EPA believes that states that incorporated the Tailoring Rule thresholds into their SIPs may take the position that they also incorporated the EPA's interpretation in the preamble that the thresholds apply to the definition ''major stationary source.''

Even so, to clarify and confirm that the Tailoring Rule thresholds apply to the section 111 prong of the definition of regulated NSR pollutant, in this proposed rulemaking, the EPA is proposing to add new provisions to the NSPS regulations, although not the PSD regulations, to make explicit that the NSPS trigger provision in the PSD regulations incorporates the Tailoring Rule thresholds.[260] Under these new provisions, to the extent that promulgation of section 111 requirements for GHGs triggers PSD requirements for GHGs, it does so only for GHGs emitted at or above the Tailoring Rule thresholds.

The EPA requests that all States with approved SIP PSD programs that apply to GHGs indicate during the comment period on this rule whether, (i) in light of EPA's interpretation that the Tailoring Rule thresholds continue to apply even when the EPA promulgates the first NSPS for GHGs, and (ii) assuming that EPA finalizes the added provisions to the section 111 regulations proposed today, they can interpret their SIPs already to apply the Tailoring Rule thresholds to the NSPS prong or whether they must revise their SIPs. For any State that says it must revise its SIP (or that does not respond), the EPA will assess whether to propose a rule shortly after the close of the comment period, to narrow its approval of that state's SIP so as to assure that for federal purposes, the Tailoring Rule thresholds will continue to apply as of the effective date of the final rule that the EPA is proposing today. Such a rule would be comparable to what we call the SIP PSD Narrowing Rule that EPA promulgated in December, 2010.[261] The EPA may finalize such a narrowing rule at the same time that it finalizes this NSPS rule.

C. Implications for BACT Determinations Under PSD

New major stationary sources and major modifications at existing major stationary sources are required by the CAA to, among other things, obtain a permit under the PSD program before commencing construction. A source is subject to PSD by way of its proposed construction and the effect of the construction and operation of the new equipment on emissions. The emission thresholds that define PSD applicability can be found in 40 CFR parts 51 and 52 and are discussed briefly in the above section.

As mentioned above, sources that are subject to PSD must obtain a

[259] This position reads the regulations to be consistent with the CAA PSD provisions themselves. Under those provisions, PSD applies to any ''major emitting facility,'' which is defined to mean stationary sources that emit or have the potential to emit ''any air pollutant'' at either 100 or 250 tons per year, depending on the source category. CAA section 165(a), 169(1). EPA has long interpreted these provisions to apply PSD to a stationary source that emits the threshold amounts of any air pollutant subject to regulation. See Tailoring Rule, 75 FR 31579. Under these provisions, at present, PSD is already applicable to GHGs because GHGs are already subject to regulation, and regulating GHGs under CAA section 111 does not create any additional type of PSD trigger.

[260] The Tailoring Rule thresholds themselves are not at issue in this rulemaking.

[261] ''Limitation of Approval of Prevention of Significant Deterioration Provisions Concerning Greenhouse Gas Emitting-Sources in State Implementation Plans; Final Rule,'' 75 FR 82536 (December 30, 2010).

preconstruction permit that contains emission limitations based on application of Best Available Control Technology for each regulated NSR pollutant. The BACT requirement is set forth in section 165(a)(4) of the CAA, and in EPA regulations under 40 CFR parts 51 and 52. These provisions require that BACT determinations be made on a case-by-case basis after consideration of the record in each case. CAA section 169(3) defines BACT as an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

Furthermore, this definition in the CAA specifies that ''[i]n no event shall application of [BACT] result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of the Act.'' This has historically been interpreted to mean that BACT cannot be less stringent than any applicable standard of performance under the NSPS. See e.g. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, p. 20–21 (March 2011). Thus, upon completion of an NSPS, EPA reads the CAA to mean that the NSPS establishes a ''BACT Floor'' for PSD permits issued to affected facilities covered by an NSPS. It is important to note that a proposed NSPS does not establish the BACT Floor for affected facilities seeking a PSD permit. This is explained on page 25 of EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011):

> In cases where a NSPS is proposed, the NSPS will not be controlling for BACT purposes since it is not a final action and the proposed standard may change, but the record of the proposed standard (including any significant public comments on EPA's evaluation) should be weighed when considering available control strategies and achievable emission levels for BACT determinations made that are completed before a final standard is set by EPA. However, even though a proposed NSPS is not a controlling floor for BACT, the NSPS is an independent requirement that will apply to an NSPS source that commences construction after an NSPS is proposed and carries with it a strong presumption as to what level of control is achievable. This is not intended to limit available options to only those considered in the development of the NSPS. (p.25)

However, once an NSPS is finalized, then the standard applies to any new source or modification that meets the applicability of the NSPS and has not commenced construction as of the date of the proposed NSPS.

It is also important to keep in mind that BACT is a case-by-case review that considers a number of factors, and the fact that a minimum control requirement is established by EPA through an NSPS does not mean that a more stringent control cannot be chosen by the permitting agency. The EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011) discusses considerations (e.g., technical feasibility, economic impacts and other costs, and environmental and energy impacts) when evaluating BACT for CO_2, as well as other greenhouse gases.

Under this proposed NSPS, an affected facility is a new EGU. In this rule we are not proposing standards for modified or reconstructed sources. However, since both a new and existing power plant can add new EGUs to increase generating capacity, this NSPS will apply to both a new, greenfield EGU facility or an existing facility that adds EGU capacity by adding a new EGU that is an affected facility under this NSPS. While this latter scenario can be considered the modification of existing sources under PSD, this proposed NSPS will not apply to modified or reconstructed sources as those terms are defined under part 60. Thus, this NSPS would not establish a BACT floor for sources that are modifying an existing EGU, for example, by adding new steam tubes in an existing boiler or replacing blades in their existing combustion turbine with a more efficient design.

Furthermore, our analysis for this proposed NSPS considers only the extent to which particular pollution control techniques are BSER for new units, and does not evaluate whether such techniques also qualify as BSER for modified or reconstructed sources under Part 60 or are otherwise achievable methods for reducing GHG emission from such sources considering economic, environmental, and energy impacts. Therefore, we do not believe that the content of this rule has any direct applicability on the determination of BACT for any part 60 modified or reconstructed sources obtaining a PSD permit.

D. Implications for Title V Program

Under the title V program, a source that emits any air pollutant subject to regulation at or above specified thresholds (along with certain other sources) is required to obtain an operating permit. This permit includes all of the CAA requirements applicable to the source. These permits are generally issued through EPA-approved State title V programs.

As the EPA explained in the Tailoring Rule preamble, title V applies to a ''major source,'' CAA section 502(a), which is defined to include, among other things, certain sources, including any ''major stationary source,'' CAA section 501(2)(B), which, in turn, is defined to include a stationary source of ''any air pollutant'' at or above 100 tpy. CAA section 302(j). The EPA's regulations under title V define the term ''major source,'' and in the Tailoring Rule, the EPA revised that definition to make clear that the term is limited to stationary sources that emit any air pollutant ''subject to regulation.'' The EPA incorporated the Tailoring Rule threshold within the definition of ''subject to regulation.'' The EPA described its action as follows in the preamble to the Tailoring Rule:

> Thus, EPA is adding the phrase ''subject to regulation'' to the definition of ''major source'' under 40 CFR 70.2 and 71.2. The EPA is also adding to these regulations a definition of ''subject to regulation.'' Under the part 70 and part 71 regulatory changes adopted, the term ''subject to regulation,'' for purposes of the definition of ''major source,'' has two components. The first component codifies the general approach EPA recently articulated in the ''Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by Clean Air Act Permitting.'' 75 FR 17704. Under this first component, a pollutant ''subject to regulation'' is defined to mean a pollutant subject to either a provision in the CAA or regulation adopted by EPA under the CAA that requires actual control of emissions of that pollutant and that has taken effect under the CAA. *See id.* at 17022–23; Wegman Memorandum at 4–5. To address tailoring for GHGs, EPA includes a second component of the definition of ''subject to regulation,'' specifying that GHGs are not subject to regulation for purposes of defining a major source, unless as of July 1, 2011, the emissions of GHGs are from a source emitting or having the potential to emit 100,000 tpy of GHGs on a CO_2e basis.

75 FR 31583.

Unlike the PSD regulations described above, the title V definition of ''major source'', as revised by the Tailoring Rule, does not on its face distinguish among types of regulatory triggers for title V. Because title V has already been triggered for GHG-emitting sources, the

promulgation of CAA section 111 requirements has no further impact on title V applicability requirements for major sources of GHGs. Accordingly, today's rulemaking has no title V implications with respect to the Tailoring Rule threshold. Of course, unless exempted by the Administrator through regulation under CAA section 502(a), sources subject to a NSPS are required to apply for, and operate pursuant to, a title V permit that assures compliance with all applicable CAA requirements for the source, including any GHG-related applicable requirements. We have concluded that this rule will not affect non-major sources and there is no need to consider whether to exempt non-major sources.

Note that we propose to move the definition of ''Greenhouse gases'' currently within the definitions of ''Subject to regulation'' in 40 CFR 70.2 and 71.2 to a definition within 70.2 and 71.2 to promote clarity in the regulations.

E. Implications for Title V Fee Requirements for GHGs

The issuance of the final EGU GHG NSPS will trigger certain requirements related to title V fees for GHG emissions under 40 CFR parts 70 and 71. States (and approved local and tribal permitting authorities) will be required to include GHG emissions in determining whether they collect adequate fees, if the state relies on the ''presumptive minimum'' approach to demonstrating fee adequacy. In addition, sources subject to federal permitting under part 71 will be required to include GHG emissions in calculating their annual permit fee.[262] The EPA is proposing changes to the title V rules to limit the impact of the requirements that would otherwise occur under the existing rules, provide flexibility to the states to ensure sufficient funding for their programs, and to ensure that the requirements are consistent with the Clean Air Act.

These requirements would be triggered because the regulation of GHGs under section 111 for the first time through the issuance of the EGU GHG NSPS would make GHGs a ''regulated air pollutant,'' as defined under 40 CFR parts 70 and 71, a ''regulated pollutant (for presumptive fee calculation)'' as defined under part 70 and a ''regulated pollutant (for fee calculation)'' as defined under part 71.

Under the current part 70, regulation of GHGs under section 111 through the issuance of any NSPS would result in GHGs being added to the list of air pollutants used in ''presumptive minimum'' fee calculations. Also, in EPA's part 71 permit program, and possibly in certain state part 70 programs, issuance of a NSPS standard would result in GHGs being added to the list of air pollutants that are subject to fee payment by sources. This effect of adding GHGs to certain title V fee requirements was not discussed in the original proposal for the EGU GHG NSPS; however, several public comments were raised on this issue, and a number of related issues, during the public comment period on the original proposal for the EGU GHG NSPS.

In this re-proposal of the EGU GHG NSPS, we discuss this issue for GHGs related to title V fees and propose rule amendments that will enable permitting authorities to collect fees as needed to support their programs, and to avoid excessive and unnecessary fees. We also respond to and clarify some related issues raised by commenters on the original proposal.

In summary, we are proposing to exempt GHGs from the presumptive fee calculation, yet account for the costs of GHG permitting program costs through a cost adjustment to ensure that fees will be collected that are sufficient to cover the program costs. We are also proposing that permitting agencies that do not use the presumptive fee approach can continue to demonstrate that their fee structures are adequate to implement their title V programs.

Prior to explaining our proposal in more detail, the following discussion provides background on the fee requirements of the title V rules, what those fees cover in terms of agencies' program implementation, what additional activities agencies might be expected to have to undertake as a result of GHGs becoming ''regulated pollutants'' under the NSPS, what the GHG Tailoring Rule said about title V fees, background on title V fees in the context of the original proposal for the EGU GHG NSPS, and existing limitations on the collection of GHG fees.

1. Background

a. The Title V Rules

Title V is implemented through 40 CFR parts 70 and 71. Part 70 defines the minimum requirements for state, local and tribal (state) agencies to develop, implement and enforce a title V operating permit program; these programs are developed by the state and the state submits a program to EPA for a review of consistency with part 70. There are about 112 approved part 70 programs in effect, with about 15,000 part 70 permits currently in effect. (See Appendix A of 40 CFR part 70 for the approval status of each state program). Part 71 is a federal permit program run by the EPA, primarily where there is no part 70 program in effect (e.g., in Indian country, the federal Outer Continental Shelf and for offshore Liquified Natural Gas terminals).[263] There are about 100 part 71 permits currently in effect (most are in Indian country).

b. The Fee Requirements of Title V

Section 502(b)(3)(A) of the Act requires owners or operators of all sources subject to permitting to ''pay an annual fee, or the equivalent over some other period, sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the permit program.'' Section 502(b)(3)(B) of the Act generally sets forth the methods for determining whether a permitting authority is collecting sufficient fees in total to cover the costs of the program. First, under the ''presumptive minimum'' approach set forth in section 502(b)(3)(B)(i), a state can satisfy the requirement by showing that ''the program will result in the collection, in the aggregate, from all sources subject to [the program] of an amount not less than $25 per ton of each regulated pollutant, or such other amount as the Administrator may determine adequately reflects the reasonable costs of the permit program.'' The statute further provides that emissions in excess of 4,000 tpy for any one pollutant need not be included in the calculation, and that the initial fee rate ($25 per ton) shall be adjusted for inflation.[264] See section 502(b)(3)(B)(iii)–(v). Also, section 502(b)(3)(B)(ii) of the Act sets forth a definition of ''regulated pollutant'' for purposes of the presumptive fee calculation that includes, in part, each pollutant regulated under section 111 of the Act, such as any pollutants regulated under any NSPS, which would make GHG a ''regulated pollutant'' based on our proposal for the EGU GHG NSPS. Each of the title V rules that implement title V contains a definition of ''regulated air

[262] Also, we understand several states may have fee requirements that are structured with similar definitions that would result in GHGs being added to the list of air pollutants that are subject to title V fees.

[263] In some circumstances, EPA may delegate authority for part 71 permitting to another permitting agency, such as a tribal agency or a state. The EPA has entered into delegation agreements for certain part 71 permitting activities with at least one tribal agency. There are currently no states that do not have an approved part 70 program; thus, there is no need for EPA to delegate part 71 permitting authority to any state at this time.

[264] The current corresponding part 70 fee rate, adjusted for inflation, is approximately $47 per ton.

pollutant''[265] (at 40 CFR 70.2 and 71.2) that tracks the Act definition of ''regulated pollutant.'' The ''regulated air pollutant'' definition is used in the regulatory text for application and other purposes and it is relevant for fee purposes because it is cross-referenced as the starting point for two fee-related definitions: ''regulated pollutant (for presumptive fee calculation)[266]'' in 40 CFR 70.2 and ''regulated pollutant (for fee calculation)[267]'' in 40 CFR 71.2.

Alternatively, if a state does not wish to show it collects an amount of fees at least equal to the presumptive minimum amount, section 502(b)(3)(B)(iv) provides that a program may be approved if the state demonstrates that it collects sufficient fees to cover the costs of the program, even if that amount is below the presumptive minimum.

The presumptive fee approach of the statute is reflected in the part 70 regulations for those states that wish to use it for fee adequacy purposes. In addition, for the federal part 71 permitting program, which the EPA implements directly, the EPA has adopted rules to ensure that it collects adequate fees, consistent with the statute. These statutory requirements for fees are reflected in 40 CFR 70.9 and 71.9, respectively.

Although the Clean Air Act and part 70 require that a title V permit program must collect sufficient fees to cover the costs of the program, neither the Act nor part 70 specifies the details of how those fees must be charged to particular sources in their fee schedules. The part 70 regulations specifically provide, at 40 CFR 70.9(b)(3), that a ''state program's fee schedule may include emission fees, application fees, service fees or other types of fees, or any combination thereof.'' Many states use emission fees and other types of fees in combination in their fee schedules and we understand that some state fee schedules are structured such that they would result in GHG fees being required when GHGs are regulated under any NSPS. For example, states may have chosen for convenience sake to use the ''regulated pollutant (for presumptive fee calculation)'' definition of part 70, or a similar state definition, to identify the pollutants subject to fees as part of their fee schedule. For part 71, the EPA chose to promulgate an emissions-based fee schedule that uses the definition of ''regulated pollutants (for fee calculation)'' to identify the pollutants subject to fees, and thus, part 71 is structured such that GHG fees would be required when GHGs are regulated under any NSPS.

State fee schedules charge emissions-based fees that range from about $15 to $100 or more per ton for each air pollutant for which they charge a fee, while part 71 charges about $48 per ton,[268] effective for calendar year 2013, for each of the ''regulated pollutants (for fee calculation).'' See 40 CFR 71.9(c)(1). Most part 70 and part 71 programs require sources to pay the fees on an annual basis, initially with the submittal of its permit application, and thereafter, on the anniversary of application submittal. See 40 CFR 70.9(a), 71.9(e).

Section 502(b)(3)(A) of the CAA broadly requires permit fees ''sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the permit program'' including the reasonable costs of: ''(i) reviewing and acting upon any application for such a permit, (ii) implementing and enforcing the terms and conditions of any such permit (not including any court costs or other costs associated with any enforcement action), (iii) emissions and ambient monitoring, (iv) preparing generally applicable regulations, or guidance, (v) modeling, analyses, and demonstrations, and (vi) preparing inventories and tracking emissions.'' These statutory requirements were incorporated into the regulations at 40 CFR 70.9(b)(1) and 71.9(b), EPA has provided detailed guidance on EPA's interpretation of this list of activities in several memoranda,[269] and these activities have been considered in the context of the ICR development and renewal process for part 70 and 71.

c. How EPA Addressed Title V Fees in the Tailoring Rule

The GHG Tailoring Rule concerned when sources are required to obtain permits under prevention of significant deterioration (PSD) and title V due to emissions of GHGs. (*See* Prevention of Significant Deterioration and Title V Greenhouse Tailoring Rule; Final Rule [the Tailoring Rule]; 75 FR 31514, June 3, 2010.) GHGs became subject to regulation as a result of the Light Duty Vehicle Rule (75 FR 25234, May 7, 2010), and the Tailoring Rule established emissions thresholds for purposes of PSD and title V. Neither the Light Duty Vehicle Rule nor the Tailoring Rule made any changes that would cause GHGs to meet the definition of ''regulated air pollutant,'' or related fee definitions in the title V regulations. The EPA has promulgated no other standards that would trigger fee requirements for GHGs in title V programs.

The GHG Tailoring Rule addressed the possible need for states and the EPA to charge fees for GHG emissions based on the burdens imposed under the Tailoring Rule for states to incorporate GHGs into permits or to issue permits to sources based on GHG emissions. We did not revise the part 70 rules to require fees for GHGs, although we did clarify that states have the option of charging fees to recover the costs of permitting related to GHGs. Also, we did not revise part 71 to require GHG fees, and we stated that we would review the need for additional fees to cover program costs for GHGs over time. (See 75 FR 31526 and 31584.) We retained this approach in last year's Step 3 Tailoring Rule. (See Prevention of Significant Deterioration and Title V Greenhouse Tailoring Rule Step 3, GHG Plantwide Applicability Limitations and GHG Synthetic Minor Limitations, (Step 3 of the Tailoring Rule), 77 FR 41051, July 12, 2012).

d. Title V Fees in the Previous EGU GHG NSPS Proposal

The previous EGU GHG NSPS proposal did not discuss any title V fee issues related to regulating GHGs under a section 111 standard; however, several public commenters (two state agencies and one industry group) raised several concerns or asked for clarification on a number of issues related to title V fees during the public comment period. Two of these commenters requested clarification as to whether the issuance of the EGU GHG NSPS would make either GHGs or CO_2 subject to regulation such that title V fee requirements would be triggered for either of these

[265] The definition includes any pollutant that is subject to any standard promulgated under section 111 of the Act.

[266] 40 CFR 70.2 defines *regulated pollutant (for presumptive fee calculation)* to include any regulated air pollutant except carbon monoxide, any pollutant that is a regulated air pollutant solely because it is a Class I or II substance subject to a standard promulgated under or established by title VI of the Act and any pollutant that is a regulated air pollutant solely because it is subject to a standard or regulation under section 112(r) of the Act.

[267] 40 CFR 71.2 defines *regulated pollutant (for fee calculation*) the same as *reegulated pollutant (for presumptive fee calculation)* in 40 CFR 70.2.

[268] Note that the part 71 fee rate and the part 70 presumptive fee rate are slightly different because the part 71 rate was set based on an analysis that showed that the EPA needed slightly more than the presumptive minimum to collect sufficient revenue to fund the program.

[269] For example, see ''Reissuance of Guidance on Agency Review of State Fee Schedules for Operating Permits Programs Under Title V''; from John S. Seitz, Director, Office of Air Quality Planning and standards, to Air Division Directors, Regions I–X; August 4, 1993; available at *http://www.epa.gov/region07/air/title5/t5memos/fees.pdf.*

pollutants. One commenter requested clarification on whether fees are required for ''regulated NSR pollutants,'' such as GHG. One commenter questioned whether the rationale of the Tailoring Rule for deferring fees for GHGs would also apply to the EGU GHG NSPS. Finally, one commenter asked us to clarify if a state could refrain from charging a fee for CO_2 (based on the issuance of the EGU GHG NSPS) if the state otherwise generates a fee sufficient to meet the ''program support requirements'' of title V. Note that we address the substance of several of these comments related to title V fees in section B of this portion of the proposal.

e. Unique Characteristics of GHGs Relative to Fees

There are a number of provisions in part 70 and part 71 and characteristics of GHGs that are relevant to any discussion related to charging fees for GHGs. First, it should be noted that GHG are emitted in extremely high quantities relative to other air pollutants, such as the criteria pollutants, which are typically emitted by combustion sources that also emit GHGs. A review of emission factors in EPA's AP–42 shows that GHGs are typically emitted in quantities as much as one thousand or more times higher than CO or NO_X and many other pollutants as a product of combustion for a given mass of fuel.[270] Thus, we expect that charging fees for GHGs at the same rate (in dollars per ton) as other regulated air pollutants would lead to fee revenue that would be excessive, far beyond the reasonable costs of the program. Even though most part 70 and 71 programs cap total fees at 4,000 tons per air pollutant per year[271] we note that the total GHG fee for a particular source under the current part 71 rule could still be significant, up to about $194,000 per year for GHGs alone, if GHGs are charged at the same rate as for other ''regulated pollutants (for fee calculation).''[272]

Second, unlike other pollutants, GHGs can be estimated in two ways: by mass or by CO_2 equivalent (CO_2e). While the title V permitting threshold for the Tailoring Rule was established at 100,000 CO_2e and 100 tpy mass, the fee provisions of part 70 and 71, and we believe the fee provisions of the majority, if not all, state programs, charge fees on a mass (per ton), rather than on a CO_2e,[273] basis. *See* 40 CFR 70.9(b)(2)(i) and 40 CFR 71.9(c)(1).

2. Response to Comments on Fees From the Previous EGU GHG NSPS Proposal

In response to concerns raised by commenters, and because response to certain of these issues will help to provide a better proposal, we respond to several of these comments at this time. In response to the question as to whether CO_2 or GHGs would be regulated by the EGU GHG NSPS, we clarify that GHG would be regulated under section 111 of the Act and that this does not affect the applicability thresholds previously established for PSD and title V in the Tailoring Rule. First, the EPA considers the pollutant being regulated by the NSPS for the purposes of PSD and title V to be GHG, rather than CO_2. Thus, under this interpretation, this NSPS has not caused CO_2 to be treated as a ''regulated air pollutant'' under the third prong of the definition of ''regulated air pollutant'' contained in 40 CFR 70.2 and 71.2, which includes ''[a]ny pollutant that is subject to any standard promulgated under section 111 of the Act,'' because it causes GHG, rather than CO_2, to be the ''regulated air pollutant.'' Second, although EPA's PSD regulations provide that regulation of GHGs under CAA section 111 triggers PSD applicability, the Tailoring Rule thresholds for GHG continue to apply for major source applicability for both the PSD and Title V permitting programs.[274] In addition, we are proposing regulatory text in section 60.46Da(f) and section 60.4315(b) to make clear that for purposes of PSD and title V, greenhouse gases (not carbon dioxide) is the pollutant subject to a standard promulgated under section 111.

In response to the comment inquiring whether the rationale of the Tailoring Rule remains relevant for deferring action on fees, we are proposing several revisions to the part 70 and part 71 regulations in response to the proposed regulation of GHGs under section 111, while retaining the general approach that we described in the Tailoring Rule. At the time of the promulgation of the Tailoring Rule, there were no section 111 standards (or other standards) that had been promulgated that would have resulted in title V fee requirements being triggered for GHGs. Thus, the rationale we use now is necessarily different than the rationale we used for the Tailoring Rule fee discussion. If the commenter is referring to the requests of certain state agencies in their comments on the Tailoring Rule for the EPA to set a presumptive fee of GHGs, we are responding to that request in this proposal by proposing to set a presumptive fee cost adjustment. If the commenter is referring to the fee flexibility afforded by 40 CFR 70.9(b)(3), we respond that we are not proposing to revise that regulatory provision. A state commenter generally asked us if it could refrain from requiring a fee for CO_2 (or GHG) if it could show that it can otherwise generate a fee sufficient to meet the ''program support requirements'' of title V. The response to this comment is yes, based on the following analysis. Title V requires permitting authorities to collect fees from sources that are ''sufficient to cover all reasonable (direct and indirect) costs required to develop and administer [title V] programs.''[275] States have adopted various fee schedules to meet this requirement. 40 CFR 70.9(b)(3) allows a State program's fee schedule to include emissions fees, application fees, service-based fees or other types of fees, or any combination thereof, to meet the requirements of the collection and retention of revenues sufficient to cover the permit program costs. Further, states are not required to calculate fees on any particular basis or in the same manner for all part 70 sources or for all regulated air pollutants, provided that they collect a total amount of fees sufficient to meet the program support requirements. This flexibility is also true for states that use the presumptive minimum approach to demonstrate they would collect sufficient fees to fund the program. In the final Tailoring Rule (75 FR 31584, June 3, 2010), we did not change our fee regulations to require title V fees for GHGs or require new fee demonstrations from states related to permitting GHGs, and we have retained

[270] See AP–42, Compilation of Air Pollution Emission Factors, Volume I, Stationary and Area Sources, Fifth Edition. For example, for external combustion of bituminous and subbituminous coals, see table 1.1–3 for NO_X and CO emission factors and table 1.1–20 for CO_2 emissions factors.

[271] Consistent with the option afforded states at 40 CFR 70.9(b)(2)(ii)(B) and the EPA's fee schedule at 40 CFR 71.9(c)(5).

[272] Note that most sources that emit GHGs, particularly major sources of GHG, also emit other regulated air pollutants subject to fees; thus, they would pay significant title V fees even if a fee for GHGs is not charged.

[273] The term ''tpy CO_2 equivalent emissions'' (or ''CO_2e'') is defined within the definition of ''subject to regulation'' in 40 CFR 70.2 and 71.2. The definitions read, in relevant part, ''[CO2e] shall represent an amount of GHGs emitted, and shall be computed by multiplying the mass amount of emissions (tpy), for each of the six greenhouse gases in the pollutant GHGs, by the gas's associated global warming potential published at Table A–1 to subpart A of part 98 of this chapter—Global Warming Potentials, and summing the resultant value for each to compute a tpy CO_2e.

[274] We have clarified these points further in a memorandum added to the docket for this rulemaking (''PSD Threshold Memorandum,'' dated May 8, 2012). See document number EPA–HQ–OAR–2011–0660–7602.

[275] The fee provisions are set forth in CAA section 502(b)(3) and in our regulations at 40 CFR 70.9 and 71.9.

the same policies for the purposes of the recent Step 3 rule (77 FR 41051, July 12, 2012). In the final Tailoring Rule, we recommended that each state, local or tribal program review its resource needs for GHGs and determine if the existing fee approaches would be adequate. If those approaches were not adequate, we suggested that they should be proactive in raising fees to cover the direct and indirect costs of the program or develop other alternative approaches to meet the shortfall. Therefore, we agree with the commenter that consistent with 40 CFR 70.9(b)(3), if a state generates fees ''sufficient to meet the program support requirements,'' without charging fees based on GHG emissions, then a fee does not have to be charged specifically for GHGs.[276] Thus, this proposal does not seek to revise fee schedule flexibility for states and instead focuses on revising the presumptive minimum fee provisions under part 70 to more appropriately account for GHG program costs. This notice does not propose any new requirements for states that do not use the presumptive approach to establish adequacy of fees.

3. Today's Proposal To Address GHGs in Title V Fees

In this part of the preamble we explain and solicit comment on options to address the title V fee issues raised by the proposed regulation of GHGs under this NSPS. In sum, we propose to exempt GHGs from the presumptive fee calculation, yet account for the costs of GHG permitting through a cost adjustment to ensure that fees will be collected that are sufficient to cover the program costs. We request comment on these proposals, particularly from state, local, and tribal permitting agencies, and particularly with respect to which approach would be most appropriate, feasible, and workable and result in fees that would be adequate to cover the direct and indirect costs of permitting GHGs. We also invite comments on ways to improve this proposal and/or address this issue in other ways consistent with the same principles, concerns, and statutory authority that we have described for this proposal.

a. Exemption of GHGs From Presumptive Fee Calculation

For the reasons discussed earlier in this proposal, we propose to exempt GHGs from the definition of ''regulated pollutant (for presumptive fee calculation)'' in 40 CFR 70.2 in order to exclude GHGs from being subject to the statutory fee rate set for the presumptive minimum fee calculation of 40 CFR 70.9(b)(2)(i). Pursuant to the authority of section 502(b)(3)(B)(i), we are proposing to determine that utilizing the statutory fee rate for GHGs would be inappropriate because it would result in excessive fees, far above the reasonable costs of a program. We are proposing a significantly smaller cost adjustment for GHGs to reflect the program costs related to GHGs.

We have estimated the cost of permitting GHGs associated with the Tailoring Rule thresholds in an economic analysis performed for the Tailoring Rule and in several documents related to Information Collection Request (ICR) requirements for part 70 and 71, and we believe these analyses provide a basis for estimating the costs related to GHG permitting for the typical permitting authority. Thus, we propose to revise 40 CFR 70.9(b)(2)(i) to add a GHG cost adjustment to account for the GHG permitting program costs.

b. Addition of a GHG Cost Adjustment to the Presumptive Minimum Fee Calculation

We propose to revise the presumptive minimum fee provisions of part 70 to add a GHG cost adjustment to account for the typical GHG permitting program costs that may not already be covered by the existing presumptive minimum fee provisions of parts 70 and 71. The current presumptive minimum fee provisions of the title V rules implements the statutory mandate to collect fees that are sufficient to cover the direct and indirect GHG program costs. Since we are not proposing to charge fees for GHGs at the statutory rate ($25 per ton, adjusted for inflation) due to concerns raised by permitting authorities and others about this resulting in excessive fees, we may need an alternative presumptive minimum fee to recover any costs related to GHGs that would not otherwise be covered by the presumptive minimum fee that is calculated based on emissions of regulated air pollutants, excluding GHGs. We estimated certain incremental GHG program costs that would not be covered under the context of the Tailoring Rule, but we did not revise our permit rule to reflect those costs at that time. We are aware that the EGU NSPS may further increase permitting authority costs above the levels that would be covered by presumptive minimum fee provisions that exclude GHGs, but we are also concerned that accounting for GHGs using the statutory rate would result in excessive calculation of costs. Thus, to address these concerns, we are proposing two alternative options to adjust the presumptive minimum fee provisions of the regulations, including a modest additional cost for each GHG-related activity of certain types that a permitting authority would process over the period covered by the presumptive minimum fee calculation, and a modest additional increase in the per ton rate used in the presumptive minimum calculation. We are also soliciting comment on an option that would calculate no additional costs for GHGs.

When we promulgate step 4 of the Tailoring Rule, and depending on EPA's proposal(s) and final action(s) there, we may revisit the GHG cost adjustment and potentially revise it, taking into account any changes in permitting authority costs for GHGs related to the obligations for permitting authorities under that rulemaking.

In addition, as a general matter, the presumptive minimum adjustments for part 70 we propose for GHGs are based, in part, on information concerning permitting authority burden (in hours) and cost (in dollars) contained in the Information Collection Request (ICR) renewal for part 70[277] approved by the Office of Management and Budget on October 3, 2012 for the 36 month period of October 31, 2012 through September 30, 2015. Also, this information is consistent with, and updates, burden and cost information in the Regulatory Impact Assessment (RIA) for the Tailoring Rule[278] and an ICR change request for the GHG Tailoring Rule (EPA ICR Number 1587.11), which was approved by OMB at the time of the promulgation of the Tailoring Rule[279]. These assumptions are relevant at least through step 3 of the implementation of the Tailoring Rule. The supporting statement for the ICR renewal for part 70 sets forth our estimate of the three-year and annual incremental burden related to certain activities performed by permitting authorities under the Tailoring Rule. (See Supporting Statement for the part 70 state Operating Permits Program, document number EPA–HQ–OAR–2004–0016–0023). The information in the supporting statement is designed to be a directionally correct assessment of costs, and thus, may serve as a starting point for considerations of

[276] Conversely, where a state cannot show that sufficient fees are being collected, the state would need to modify its fee schedule (which could, but need not, involve charging fees for GHG emissions).

[277] The most recent part 70 ICR renewal is identified as EPA ICR number 1587.12 and the ICR for part 70 has been assigned OMB control number 2060–0243.

[278] Regulatory Impact Analysis for the Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, Final Report, May 2010.

[279] The ICR change request form for the Tailoring Rule was based on the assumptions made in the RIA for the Tailoring Rule.

the possible range of costs to consider when proposing adjustments to the presumptive minimum fee provisions of part 70 to appropriately account for GHG permitting program costs.

First, we are proposing to adjust the presumptive minimum fee to account for GHG costs by adding a cost for each GHG-related activity of certain types that a permitting authority may perform over the period covered by a presumptive minimum fee calculation. Additional information supporting this approach may be found in part in Table 12 of the supporting statement (in the ICR) summarizing the permitting authority burden for particular GHG-related permitting activities. Table 12 in the ICR shows certain incremental burden assumptions for certain activities related to GHG permitting program costs in the form of an hourly burden for each activity that a permitting authority may process. Based on observations regarding permitting activities since the Tailoring Rule, we have adapted these assumptions for the purposes of this option and included certain activities with a somewhat different description than we used in the table in the ICR in an attempt to more accurately reflect the types of permitting activities that have occurred in the GHG permit program. In addition, by making these clarifying changes, we are trying to more closely track the language in the CAA and parts 70 and 71 regarding the specific of the permit process. We are proposing to include three general activities in this proposed option: (1) ''GHG completeness determination (for initial permits or for updated applications)'' at 43 hours, (2) ''GHG evaluation for a modification or related permit action'' at 7 hours, and (3) ''GHG evaluation at permit renewal'' at 10 burden hours.[280] The GHG cost adjustment for the presumptive fee would be calculated under this approach by multiplying the burden hours for each activity by the cost of staff time (in $ per hour), including wages, benefits, and overhead, as determined by the state for the particular activities undertaken. We also solicit comment on the specific burden hours we propose for these GHG-related activities. The proposed burden hours for the three activities above were not directly discussed in the ICR or directly subject to public comment in that context. We believe this proposal would benefit from state input on the burden hour assumptions for the activities identified and we solicit comment the burden hour assumptions and on additional GHG-related permitting activities that should be added to the list.

We are also co-proposing an alternative option under which we would increase the fee rate used in the presumptive minimum calculation for each regulated air pollutant, excluding GHGs. This option would rely primarily on data concerning the state burdens of permitting GHGs through step 3 of the tailoring rule found in the Information Collection Request (ICR) for part 70. This suggests that when looking at Tailoring Rule burden in isolation, that GHG permitting increases permitting authority burden by about 7 percent above the baseline burden,[281] which would be multiplied by the presumptive minimum fee rate in effect to calculate the revise presumptive fee rate to account for GHG. Under this approach, the new presumptive minimum fee effective for the current period would be $50.00 per ton for each regulated pollutant (for presumptive fee calculation).[282] Several states suggested an approach similar to this in comments on the Tailoring Rule, however, their comments assumed we would not be exempting GHGs from the definition of regulated pollutants (for presumptive fee calculation), as we are proposing today. We solicit comment on the appropriateness of the 7 percent fee increase for the presumptive minimum fee we propose to account for the GHG permitting costs for permitting authorities under this alternative option. We are particularly interested in state input on whether this level should be higher or lower than we propose.

The two options we co-propose for adjusting the presumptive minimum fee to account for the costs of GHG permitting are similar in that we believe they would both result in about the same amount of additional fee revenue being collected. For the first option, we took the assumptions approved into the ICR and adapted them somewhat so that they more accurately reflect the actual implementation experience of permitting authorities related to GHGs. On the second, alternative option, we used the ICR estimate to determine the relative contribution of GHG tailoring rule costs to the total costs of title V permitting and we assume these relative costs will hold true in any particular state that uses the presumptive minimum fee approach to demonstrating fee adequacy. The two options differ in that the first option calculates the GHG adjustment to the presumptive fee minimum by determining the number of actual GHG-related activities they have performed for a period, while the second option calculates the GHG adjustment by increasing the presumptive fee rate for non-GHG pollutants by a set ratio to reflect average expected costs. The first approach requires a state to track the number of activities of these types it is performing and is thus more burdensome to calculate, although it may more accurately reflect the actual costs. The second approach is simpler to calculate and predictable but is less directly tied to actual implementation experience in a particular state.

We also solicit comment on whether we need to revise the presumptive minimum calculation provisions to account for GHGs costs if we exempt GHGs from the calculation of the presumptive minimum fee. The basis for this option would be that because most GHG sources that would be subject to title V permitting, whether due to GHGs or due for other reasons under the proposed NSPS and applicability provisions of the permitting rules (see 40 CFR 70.3 and 71.3) would have actual emissions of other regulated air

[280] A completeness determination is the first step performed by the permitting authority once a permit application is received. This step is generally more time consuming for an initial permit application compared to other permit applications because this is the initial evaluation leading to the drafting and issuance of the permit for the first time. Because GHG permitting is in the early stages of implementation and EPA is in the early stages of issuing new applicable requirements for GHGs, we believe permitting authorities will experience additional burdens related to GHGs as part of this initial completeness determination. Thus, the first item, ''GHG completeness determination (for initial permit or update application)'' reflects these additional burdens for completeness determinations related to GHGs. This item would also cover subsequent application updates related to an initial application. See, e.g., 40 CFR 70.5(a)(2). The second item, ''GHG evaluation for a permit modification or related permitting action'' applies where a permitting authority undertakes an evaluation of whether a permit modification involves any GHG-related requirements. This might also occur, for example, where a synthetic or true minor application is submitted and the permitting authority needs to undertake a GHG related analysis to determine if it affects the existing title V permit. The third item, ''GHG evaluation at permit renewal'' applies where the permitting authority receives a renewal application that is not coupled with any facility modifications. The EPA suggests this language because it is more closely tied to the specific work to be performed by permitting authorities consistent with statutory and regulatory obligations.

[281] The baseline costs in the supporting statement for the ICR were the costs of permitting looking at all activities except for those related to the GHG tailoring rule and certain other recent rule changes. Table 14 of the supporting statement shows a permitting authority burden of 102,122 hours for implementing the GHG tailoring rule and 1,414,293 hours of baseline permitting authority burden, and Table 15 shows a permitting authority cost of $5.5 million for implementing the GHG tailoring rule and $76.4 million for the baseline permitting program.

[282] At the current rate for part 70 of $46.73, this would result in a GHG fee adjustment of about $3.27, or a new rate of $50.00 per ton for each regulated pollutant (for presumptive fee calculation).

pollutants subject to fees, and thus the cost of permitting these sources may be adequately accounted for without charging any additional fees specifically based on emissions of GHGs. We also note that support for this approach can be found in the current OMB-approved ICR for part 70, tables 14, 15 and 18, where the cost of permitting for permitting authorities is summarized, considering the effects of several recent EPA rulemakings that were conducted since the last ICR update.

This proposal does not directly affect those states that do not rely on the presumptive minimum fee approach to show fee adequacy; however, non-presumptive fee states are still required to charge sufficient fees to recover all reasonable direct and indirect program costs. Part 70 allows the EPA to review state fee programs at any time to determine if they are collecting fees sufficient to cover their costs, whether or not states rely on the presumptively minimum fee approach. We are not requiring any additional detailed fee submittals from states at this time based on these proposed changes.

Some states may conclude that they wish to revise their part 70 programs in response to this proposal either to revise their state fee schedules to prevent any possible collection of excessive fees (e.g., if they require any regulated pollutant subject to a section 111 standard to pay a fee) or to charge additional fees to sources because their presumptive minimum fee target has increased. We solicit comment on the most expeditious means for EPA to approve title V program revisions across the states once this proposal is finalized.

There may be other viable options consistent with statutory and regulatory authority, principles, and concerns, in addition to those we have described in this proposal. For example, states have previously commented on establishing a separate, lower presumptive fee per ton of GHG emissions). The EPA invites states, local, and/or Tribal authorities to provide more refined data and/or information surrounding the unique costs associated with permitting GHG sources under this proposed rule, and other fee options such data supports. Notably, the regulatory text included today represents only one option on which comments are solicited. The EPA is providing full regulatory text only for this option because it represents the most novel approach. The EPA is also soliciting comment on other viable approaches described herein, but considers the discussion provided herein to provide an adequate basis for public comment. The EPA notes that the final rule may be based on any of the approaches described in the preamble.

c. Revisions to the Part 71 Fee Schedule

As part of the promulgation of the final part 71 rule, the EPA performed a detailed analysis of the costs of developing and implementing the program and reviewed the inventory of emissions of regulated pollutants (for fee calculation) to determine the appropriate emission fee that would be sufficient to recover all direct and indirect programs costs—we set the fee at $32 per ton, adjusted for inflation, times the emissions of regulated pollutant (for fee calculation). (*See* Federal Operating Programs Fees, Revised Cost Analysis, February 1996; legacy docket A–93–51, document number II–A–3.)

For part 71, we also propose to exempt GHGs from the definition of regulated pollutant (for fee calculation), which is similar to the definition of regulated pollutants (for presumptive fee calculation) used in part 70, for the same reasons we have explained for part 70. In addition, for the same reasons we explained for part 70, we are proposing two options for revising the fee schedule of 40 CFR 71.9(c) to ensure that we continue to recover sufficient fees to fully fund the part 71 GHG permitting program. The bases for the options were described in more detail earlier in this proposal with respect to part 70 proposals and those also apply here to part 71.

First, the EPA (or delegate agency) burden hour assumptions we propose for each GHG-related permitting activity under part 71 are the same as we are proposing for states under the presumptive minimum fee provisions of part 70.[283] This option would rely on the following information. The labor rate assumption we propose for the EPA (or delegate agency) staff time under part 71 is the average hourly rate we assumed in the supporting statement for the recent part 71 ICR renewal of $52 per hour in 2011 dollars, including wages, benefits and overhead costs. We propose to determine the GHG fee adjustment for each GHG permitting program activity by multiplying the burden hour assumption we propose by the EPA (or delegate agency) labor rate we propose. Thus, for example, we propose a set fee to be paid by sources for each ''completeness determination (for new permit or updated application)'' of $364 (7 hours times $52 per hour for the current period). Also, we propose to charge, for simplicity sake, the same set fees for GHG activities, whether performed by the EPA, a delegate agency, or by the EPA with contractor assistance. The appropriate set fees for all GHG permitting program activities performed for the source would be added to the traditional fee that is determined based on emissions of each regulated pollutant (for fee calculation) to determine the total fee for the source.

The second option we propose for part 71 is to increase the emission fee by a modest amount for each regulated air pollutant, excluding GHGs. For simplicity sake, we propose to charge the same adjustment under this option that we propose for part 70, or 7 percent, which would be multiplied by annual part 71 fee in effect to calculate the revise fee rate.[284] The rationale for this approach is described in more detail earlier in this preamble during the part 70 discussion.

We also solicit comment on whether we could exclude GHG emissions from the calculation of the annual part 71 fee for reasons similar to those we explained for part 70 (e.g., because permitting costs can be covered by the existing part 71 permit fee).

X. Impacts of the Proposed Action [285]

A. What are the air impacts?

As explained in the Regulatory Impact Analysis (RIA) for this proposed rule, available data indicate that, even in the absence of this rule, existing and anticipated economic conditions will lead electricity generators to choose new generation technologies that would meet the proposed standard without installation of additional controls. Therefore, based on the analysis presented in Chapter 5 of the RIA, the EPA projects that this proposed rule will result in negligible CO_2 emission changes, quantified benefits, and costs by 2022.[286]

[283] See the supporting statement for the ICR renewal for part 71 approved by the Office of Management and Budget on June 13, 2012 for the 36 month period of June 30, 2012 through May 31, 2015. The ICR renewal for part 71 is identified as EPA ICR number 1713.10 and the ICR for part 71 has been assigned OMB control number 2060–0336. The assumptions of this part 71 ICR renewal for GHG burden are identical to those used for the part 70 ICR. See Table 12 of the part 71 supporting statement.

[284] At the current rate for part 71 of $48.33, this would result in a GHG fee adjustment of $3.38, or a new rate of $51.71 per ton for each regulated pollutant (for fee calculation).

[285] Note that 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.

[286] Conditions in the analysis year of 2022 are represented by a model year of 2020.

B. What are the energy impacts?

This proposed rule is not anticipated to have a notable effect on the supply, distribution, or use of energy. As previously stated, the EPA believes that electric power companies would choose to build new EGUs that comply with the regulatory requirements of this proposal even in its absence, because of existing and expected market conditions. In addition, the EPA does not project any new coal-fired EGUs without CCS to be built in the absence of this proposal.

C. What are the compliance costs?

The EPA believes this proposed rule will have no notable compliance costs associated with it, because electric power companies would be expected to build new EGUs that comply with the regulatory requirements of this proposal even in the absence of the proposal, due to existing and expected market conditions. The EPA does not project any new coal-fired EGUs without CCS to be built in the absence of the proposal. However, because some companies may choose to construct coal or other fossil fuel-fired units, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired unit with CCS.

D. How will this proposal contribute to climate change protection?

As previously explained, the special characteristics of GHGs make it important to take initial steps 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-fueled power plants emit more GHG emissions than any other stationary source category in the United States, and among new GHG emissions sources, the largest individual sources are in this source category.

This proposed rule will limit GHG emissions from new sources in this source category to levels consistent with current projections for new fossil fuel-fired generating units. The proposed rule will also serve as a necessary predicate for the regulation of existing sources within this source category under CAA section 111(d). In these ways, the 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?

The EPA does not anticipate that this proposed rule will result in notable CO_2 emission changes, energy impacts, monetized benefits, costs, or economic impacts by 2022. The owners of newly built electric generating units will likely choose technologies that meet these standards even in the absence of this proposal due to existing economic conditions as normal business practice. Likewise, the EPA believes this rule will not have any impacts on the price of electricity, employment or labor markets, or the U.S. economy.

F. What are the benefits of the proposed standards?

As previously stated, the EPA does not anticipate that the power industry will incur compliance costs as a result of this proposal and we do not anticipate any notable CO_2 emission changes resulting from the rule. Therefore, there are no direct monetized climate benefits in terms of CO_2 emission reductions associated with this rulemaking. However, by clarifying that in the future, new coal-fired power plants will be required to meet a particular performance standard, this rulemaking reduces uncertainty and may enhance the prospects for new coal-fired generation and the deployment of CCS, and thereby promote energy diversity.

XI. Request for Comments

We request comments on all aspects of the proposed rulemaking including the RIA. All significant comments received will be considered in the development and selection of the final rule. We specifically solicit comments on additional issues under consideration as described below.

Measurement. We are requesting comment on requiring the use the following procedures that increase the precision of GHG measurements:

a. EPA Method 2F of 40 CFR part 60 for flow rate measurement during the relative accuracy test audit and performance testing. Method 2F provides velocity data for three dimensions and provides measurements more representative of actual gas flow rates than EPA Method 2 or 2G of 40 CFR part 60.

b. EPA Method 2H of 40 CFR part 60 or Conditional Test Method (CTM)-041 (see: *http://www.epa.gov/airmarkets/emissions/docs/square-ducts-wall-effects-test-method-ctm-041.pdf*) to account for wall effects for stack gas flow rate calculations during CEMS relative accuracy determinations and for performance testing.

c. EPA Method 4 of 40 CFR part 60 to determine moisture for flow rate during CEMS relative accuracy determinations and for performance test calculations.

d. EPA Method 3A of 40 CFR part 60 for CO_2 concentration measurement and for molecular weight determination during CEMS relative accuracy determinations or for performance testing.

e. An ambient air argon concentration of 0.93 percent [287] and a molecular weight of 39.9 lb/lb-mol in calculating the dry gas molecular weight.

f. A value for pi of 3.14159 when calculating the effective area for circular stacks.

g. A daily calibration drift cap no greater than 0.3 percent CO_2 for CO_2 CEMS.

h. A maximum relative accuracy specification of 2.5 percent for both CO_2 and flow rate measurement CEMS.

i. Method 3B of 40 CFR part 60 in addition to Method 3A, for CO_2 concentration measurement and for molecular weight determination during CEMS relative accuracy determinations or for performance testing.

Coal refuse. In the original proposal, we requested comment on subcategorizing EGUs that burn over 75 percent coal refuse on an annual basis. Multiple commenters supported the exemption, citing numerous environmental benefits of remediating coal refuse piles. Other commenters disagreed with any exemption, specifically citing the N_2O emissions from fluidized bed boilers (coal refuse-fired EGUs typically use fluidized bed technology). Due to the environmental benefits of remediating coal refuse piles cited by commenters, the limited amount of coal refuse, and that a new coal refuse-fired EGU would be located in close proximity to the coal refuse pile, we are continuing to consider establishing a subcategory for coal refuse-fired EGUs and are requesting additional comments. Specifically, we are requesting additional information on the net environmental benefits of coal refuse-fired EGUs, and in the event we do establish a coal refuse-fired subcategory, what the emissions standard for that subcategory should be (i.e., should it be based on a lower amount of partial CCS or on highly efficient generation alone, without the use of CCS). One commenter on the original proposal stated that existing coal refuse piles are naturally combusting at a rate of 0.3 percent annually. We are requesting comment

[287] *http://www.physicalgeography.net/fundamentals/7a.html.*

on assuming this rate of natural combustion and the proper approach to accounting for naturally occurring emissions from coal refuse piles.

Compressed Air Energy Storage (CAES) Facilities. CAES technology is an energy storage technology that involves two steps. Air is compressed by electric motor driven compressors during off-peak electricity demand hours and stored in a storage media (e.g., an underground cavern). Electricity is then generated during peak electricity demand periods by releasing the high-pressure air, heating the air with natural gas, and expanding it through sequential turbines (expanders), which drive an electrical generator. Since natural gas is combusted in the stationary combustion turbine, a new CAES would potentially have to comply with one of the proposed emissions standards. However, based on anticipated capacity factors for new CAES facilities, it is our understanding that the proposed one-third electric sales of potential electric output applicability criteria would exempt new CAES facilities from the proposed emission standards. The EPA is requesting comment on whether this assumption is accurate. In the event that this is not the case, the EPA is considering and requesting comment on if new source review is the appropriate mechanism to establish site specific GHG requirements for CAES facilities and, if so, whether the EPA should exempt stationary combustion turbines at CAES facilities from the proposed CO_2 emission standards. We have concluded this could be appropriate since we expect only a limited number of new CAES facilities, and the use of stored energy complicates the determination of compliance with the proposed emission standards.

District Energy. District energy systems produce steam, hot water or chilled water at a central facility. The steam, hot water or chilled water is then distributed through pipes to individual consumers for space heating, domestic hot water heating and air conditioning. As a result, individual consumers served by a district energy system do not need their own heating, water heating or air conditioning systems. Even though with the proposed definition of net-electric output it is unlikely that a district energy system would be subject to an emissions standard, we are considering and requesting comment on an appropriate method to recognize the environmental benefit of district energy systems. The steam or hot water distribution system of a district energy system located in urban areas, college and university campuses, hospitals, airports, and military installations eliminates the need for multiple, smaller boilers at individual buildings. A central facility typically has superior emission controls and consists of a few larger boilers facilitating more efficient operation than numerous separate smaller individual boilers. However, when the hot water or steam is distributed, approximately two to three percent of the thermal energy in the water and six to nine percent of the thermal energy in the steam is lost, reducing the net efficiency advantage. To recognize the net environmental benefit of district energy systems compared to multiple smaller heating and cooling systems, we are requesting comment on whether it is appropriate to adjust the measured thermal output from district energy systems when calculating the emissions rate used for compliance purposes. For example, if thermal energy from central district energy systems is approximately 5 percent more efficient than thermal energy supplied by multiple smaller heating and cooling systems, the measured thermal output would be divided by 0.95 (e.g., 100 MMBtu/h of measured steam would be 105 MMBtu/h when determining the emissions rate). This approach would be similar to the proposed approach to how the electric output for CHP is considered when determining regulatory compliance and is consistent with the approach in the proposed amendments to the combustion turbine NSPS (77 FR 52554). We request that comments include technical analysis of the net benefits in support of any conclusions on an appropriate adjustment factor.

Emergency conditions. We are requesting comment on excluding electricity generated as a result of a grid emergency declared by the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator from counting as net sales when determining applicability as an EGU. For example, under this approach, if grid voltage drops below acceptable levels and the affected facility is the only facility with available capacity, then electricity generated during this period would not count for applicability purposes. While the proposed 3 year average electric sales applicability provides significant flexibility for simple cycle turbines, we are considering including the emergency conditions exemption to allow facilities designed with the intent to sell less than one-third of their potential electric output to continue to generate electricity during a grid emergency without such generation counting towards the one-third sales applicability criterion. In the original 1979 electric utility NSPS rulemaking (44 FR 33580), the EPA recognized that emergency periods do occur from unplanned EGU outages, transmission outages or surging customer demand loads. Such occurrences may require that all available operable EGUs interconnected to the electrical grid supply power to the grid. Provisions were added to 40 CFR part 60, subpart Da to address emergency conditions when continued operation of an EGU with a malfunctioning flue gas desulfurization (FGD) system is acceptable and not considered a violation of the SO_2 emissions standard. These conditions require that all available capacity from the power company's other EGUs is being used and all available purchase power from interconnected power companies is being obtained. In this case, the EPA concluded that the broader benefits of operating the power plant with the malfunctioning FGD system to generate electrical power during emergency conditions in order to ensure uninterrupted electricity supply to the public outweigh any adverse impacts from a short-term increase in SO_2 emission to the atmosphere from the power plant. The definition for a system emergency we are considering is ''any abnormal system condition that the Regional Transmission Organizations (RTO), Independent System Operators (ISO) or control area Administrator determines requires immediate automatic or manual action to prevent or limit loss of transmission facilities or generators that could adversely affect the reliability of the power system and therefore call for maximum generation resources to operate in the affected area, or for the specific affected facility to operate to avert loss of load.''

Initial Design Efficiency Test. We are considering and requesting comment on requiring an initial performance test for stationary combustion turbines in addition to the 12-operating-month rolling average standard. Requiring an initial compliance test that is numerically more stringent than the annual standard for new combined cycle facilities would insure that the most efficient stationary combustion turbines are installed. The less stringent 12-month rolling average standard would be set at a level that would take into account actual operating conditions.

Integrated Equipment. The proposed affected facility definitions include the traditional generating unit ''plus any integrated equipment that provides electricity or useful thermal output.''

For example, the definition of a steam generating unit for GHG purposes, ''means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included) *plus any integrated equipment that provides electricity or useful thermal output to either the boiler or to power auxiliary equipment''* (emphasis added). We are considering and requesting comment on also including in the definition of the affected facility co-located non-emitting energy generation equipment that is not integrated into the operation of the affected facility. This approach would provide additional flexibility, lower compliance costs, and recognize the environmental benefit of non-emitting sources of electricity and not limit options to integrated solar thermal. The definition would include the additional language ''or co-located non-emitting energy generation included in the facility operating permit.'' For example, the definition of a steam generating unit for GHG purposes would be expanded to read, ''any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to either the boiler or to power auxiliary equipment *or co-located non-emitting energy generation included in the facility operating permit''* (emphasis added). This would permit the use of co-located photovoltaic solar power, wind turbines, and other non-emitting energy generation as means for achieving compliance with the emission standards. Since integrated solar thermal is primarily a feasible option only for facilities that operate daily (e.g., thermal energy from the solar thermal is used in the steam cycle generated from the combustion of fossil fuels), this approach would expand options for more intermittent intermediate load generators to efficiently integrate non-emitting energy generation into their design.

Other GHGs. Today's proposed rule would require continuous measurement of CO_2 from fossil fuel-fired EGUs. Other GHGs, such as CH_4 and N_2O are not included in the proposed emission standards and are also not required to be measured and reported by affected EGUs as part of today's proposal, even though their 100-year global warming potential is 21 to 310 times greater than that of CO_2, because their emissions from EGUs are believed to be negligible when compared to CO_2 emissions. We request comment on the appropriateness, technique, and frequency (one-time or periodic, but not continuous) of measurement and reporting of CH_4 and N_2O emissions from fossil fuel-fired EGUs as part of the proposed emissions standard. Receipt of this data would enhance understanding of total GHG emissions from EGUs and could aid future policy decisions regarding whether these GHGs should be included in a revised emission standard, as part of 8-year NSPS review and potential revision cycle.

Violations. We are proposing that the calculation of the number of daily violations within an averaging period be determined using the following methodology. If, for any 12- or 84-operating month period, the source's emission rate exceeds the standard, the number of daily violations in the 12- or 84-operating-month averaging period would be the number of operating days in that period. However, if a violation occurs directly following the previous 12-operating-month or 84-operating-month averaging period, daily violations would not double count operating days that were determined as violations under the previous averaging period. For example, assume that a facility operates 10 days out of each month for 12 months from January 1, Year 1 to December 31, Year 1, and exceeds the emissions standard during that 12-month period. The violation for this January-December Year 1 period would constitute 120 daily violations. If the facility operated 20 days the following month, which would be January, Year 2, and was still in excess of the emissions standard over the period from February, Year 1 to January, Year 2, then 20 additional daily violations would result, for a total of 140 daily violations. We are requesting comment on this determination of daily violations for owners/operators that exceeds either a 12-operating-month or 84-operating-month standard.

XII. 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 (EO) 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 Office of Management and Budget (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. In addition, the EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the Regulatory Impact Analysis for the Standards of Performance for Greenhouse Gas Emissions for New Fossil Fuel-Fired Electric Utility Steam Generating Units and Stationary Combustion Turbines.

The EPA believes this rule will have no notable compliance costs associated with it over a range of likely sensitivity conditions because electric power companies would choose to build new EGUs that comply with the regulatory requirements of this proposal even in the absence of the proposal, because of existing and expected market conditions. (See the RIA for further discussion of sensitivities). The EPA does not project any new coal-fired EGUs without CCS to be built in the absence of this proposal. However, because some companies may choose to construct coal or other fossil fuel-fired units, the RIA also analyzes project-level costs of a unit with and without CCS, to quantify the potential cost for a fossil fuel-fired unit with CCS.

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 2465.02.

This proposed action would impose minimal new information collection burden on affected sources beyond what those sources would already be subject to under the authorities of CAA parts 75 and 98. 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 certain reporting costs based on requirements in the NSPS General Provisions (40 CFR part 60, subpart A), which are mandatory for all owners/operators subject to CAA section 111 national emission standards, there are 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.

The EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this proposal because of existing and expected market conditions. The EPA does not project any new coal-fired EGUs that commence construction after this proposal to commence operation over the 3-year period covered by this ICR. We estimate that 17 new affected NGCC units would commence operation during that time period. As a result of this proposal, those units would be required to prepare a summary report, which includes reporting of emissions and downtime, every 3 months.

When a malfunction occurs, sources must report them according to the applicable reporting requirements of 40 CFR part 60, subparts Da and KKKK or subpart TTTT 60.5530. An affirmative defense to civil penalties for exceedances of emission limits that are caused by malfunctions is available to a source if it can demonstrate that certain criteria and requirements are satisfied. The criteria ensure that the affirmative defense is available only where the event that causes an exceedance of the emission limit meets the narrow definition of malfunction (sudden, infrequent, not reasonably preventable, and not caused by poor maintenance or careless operation) and where the source took necessary actions to minimize emissions. In addition, the source must meet certain notification and reporting requirements. For example, the source must prepare a written root cause analysis and submit a written report to the Administrator documenting that it has met the conditions and requirements for assertion of the affirmative defense.

To provide the public with an estimate of the relative magnitude of the burden associated with an assertion of affirmative defense, the EPA has estimated what the notification, recordkeeping, and reporting requirements associated with the assertion of the affirmative defense might entail. The EPA's estimate for the required notification, reports, and records, including the root cause analysis, associated with a single incident totals approximately totals $3,141, and is based on the time and effort required of a source to review relevant data, interview plant employees, and document the events surrounding a malfunction that has caused an exceedance of an emission limit. The estimate also includes time to produce and retain the record and reports for submission to the EPA. The EPA provides this illustrative estimate of this burden, because these costs are only incurred if there has been a violation, and a source chooses to take advantage of the affirmative defense.

Given the variety of circumstances under which malfunctions could occur, as well as differences among sources' operation and maintenance practices, we cannot reliably predict the severity and frequency of malfunction-related excess emissions events for a particular source. It is important to note that the EPA has no basis currently for estimating the number of malfunctions that would qualify for an affirmative defense. Current historical records would be an inappropriate basis, as this rule applies only to sources built in the future. Of the number of excess emissions events that may be reported by source operators, only a small number would be expected to result from a malfunction, and only a subset of excess emissions caused by malfunctions would result in the source choosing to assert an affirmative defense. Thus, we believe the number of instances in which source operators might be expected to avail themselves of the affirmative defense will be extremely small. In fact, we estimate that there will be no such occurrences for any new sources subject to 40 CFR part 60, subpart Da and subpart KKKK or subpart TTTT over the 3-year period covered by this ICR. We expect to gather information on such events in the future, and will revise this estimate as better information becomes available.

The annual information collection burden for this collection consists only of reporting burden as explained above. The reporting burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $15,570 and 396 labor hours. This estimate includes quarterly summary reports which include reporting of emissions and downtime. All burden estimates are in 2010 dollars. Average burden hours per response are estimated to be 8 hours. The total number of respondents over the 3-year ICR period is estimated to be 36. 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–2013–0495. Submit any comments related to the ICR to the EPA and OMB. See **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 Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after January 8, 2014, a comment to OMB is best assured of having its full effect if OMB receives it by February 7, 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 defined as having a total electric output of 4 million MWh or less in the previous fiscal year. The NAICS codes for the affected industry are in Table 8 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 8—POTENTIALLY REGULATED CATEGORIES AND ENTITIES [a]

Category	NAICS Code	Examples of potentially regulated entities
Industry	221112	Fossil fuel electric power generating units.
State/Local Government	[b] 221112	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.

We do not include an analysis of the illustrative impacts on small entities that may result from implementation of this proposed rule because we do not anticipate any compliance costs over a range of likely sensitivity conditions as a result of this proposal. Thus the cost-to-sales ratios for any affected small entity would be zero costs as compared to annual sales revenue for the entity. The EPA believes that electric power companies will choose to build new EGUs that comply with the regulatory requirements of this proposal because of existing and expected market conditions. (See the RIA for further discussion of sensitivities). The EPA does not project any new coal-fired EGUs without CCS to be built. Accordingly, there are no anticipated economic impacts as a result of this proposal.

Nevertheless, the EPA is aware that there is substantial interest in this rule among small entities (municipal and rural electric cooperatives). In light of this interest, prior to the April 13, 2012 proposal (77 FR 22392), the EPA determined to seek early input from representatives of small entities while formulating the provisions of the proposed regulation. Such outreach is also consistent with the President's January 18, 2011 Memorandum on Regulatory Flexibility, Small Business, and Job Creation, which emphasizes the important role small businesses play in the American economy. This process has enabled the EPA to hear directly from these representatives, at a very preliminary stage, about how it should approach the complex question of how to apply Section 111 of the CAA to the regulation of GHGs from these source categories. The EPA's outreach regarded planned actions for new and existing sources, but only new sources would be affected by this proposed action.

The EPA conducted an initial outreach meeting with small entity representatives on April 6, 2011. The purpose of the meeting was to provide an overview of recent EPA proposals impacting the power sector. Specifically, overviews of the Transport Rule, the Mercury and Air Toxics Standards, and the Clean Water Act 316(b) Rule proposals were presented.

The EPA conducted outreach with representatives from 20 various small entities that potentially would be affected by this rule. The representatives included small entity municipalities, cooperatives, and private investors. We distributed outreach materials to the small entity representatives; these materials included background, an overview of affected sources and GHG emissions from the power sector, an overview of CAA section 111, an assessment of CO_2 emissions control technologies, potential impacts on small entities, and a summary of the listening sessions. We met with eight of the small entity representatives, as well as three participants from organizations representing power producers, on June 17, 2011, to discuss the outreach materials, potential requirements of the rule, and regulatory areas where the EPA has discretion and could potentially provide flexibility.

A second outreach meeting was conducted on July 13, 2011. We met with nine of the small entity representatives, as well as three participants from organizations representing power producers. During the second outreach meeting, various small entity representatives and participants from organizations representing power producers presented information regarding issues of concern with respect to development of standards for GHG emissions. Specifically, topics suggested by the small entity representatives and discussed included: boilers with limited opportunities for efficiency improvements due to NSR complications for conventional pollutants; variances per kilowatt-hour and in heat rates over monthly and annual operations; significance of plant age; legal issues; importance of future determination of carbon neutrality of biomass; and differences between municipal government electric utilities and other utilities.

While formulating the provisions of this proposed regulation, the EPA also considered the input provided in the over 2.5 million public comments on the April 13, 2012 proposed rule (77 FR 22392). We invite comments on all aspects of the proposal and its impacts, including potential adverse 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. The EPA believes this proposed rule will have no compliance costs associated with it over a range of likely sensitivity conditions because electric power companies will choose to build new EGUs that comply with the regulatory requirements of this proposal because of existing and expected market conditions. (See the RIA for further discussion of sensitivities). The EPA does not project any new coal-fired EGUs without CCS to be built. Thus, 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 in this rule among governmental entities, the EPA initiated consultations with governmental entities prior to the April 13, 2012 proposal (77 FR 22392). The EPA invited the following 10 national organizations representing state and local elected officials to a meeting held 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. The purposes of the consultation were to provide general background on the proposal, answer questions, and solicit input from state/local governments. The EPA's consultation regarded planned actions for new and existing sources, but only new sources would be affected by this proposed action.

During the meeting, officials asked clarifying questions regarding CAA section 111 requirements and efficiency improvements that would reduce CO_2 emissions. In addition, they expressed concern with regard to the potential burden associated with impacts on state and local entities that own/operate affected utility boilers, as well as on state and local entities with regard to implementing the rule. Subsequent to the April 12, 2011 meeting, the EPA received a letter from the National Conference of State Legislatures. In that letter, the National Conference of State Legislatures urged the EPA to ensure that the choice of regulatory options maximizes benefit and minimizes implementation and compliance costs on state and local governments; to pay particular attention to options that would provide states with as much flexibility as possible; and to take into consideration the constraints of the state legislative calendars and ensure that sufficient time is allowed for state actions necessary to come into compliance.

While formulating the provisions of this proposed regulation, the EPA also considered the input provided in the over 2.5 million public comments on the April 13, 2012 proposed rule (77 FR 22392).

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 EO 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. Prior to the April 13, 2012 proposal (77 FR 22392), the EPA consulted with state and local officials in the process of developing the proposed rule to permit them to have meaningful and timely input into its development. The EPA's consultation regarded planned actions for new and existing sources, but only new sources would be affected by this proposed action. The EPA met with 10 national organizations representing state and local elected officials to provide general background on the proposal, answer questions, and solicit input from state/local governments. The UMRA discussion in this preamble includes a description of the consultation. While formulating the provisions of this proposed regulation, the EPA also considered the input provided in the over 2.5 million public comments on the April 13, 2012 proposed rule (77 FR 22392). In the spirit of EO 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 new 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 does not affect existing sources such as the three coal-fired EGUs located in Indian Country, but addresses CO_2 emissions for new EGU sources only. Thus, Executive Order 13175 does not apply to this action.

Although Executive Order 13175 does not apply to this action, EPA consulted 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), 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, but only new sources would be affected by this proposed action.

Consultation letters were sent to 584 tribal leaders. The letters provided information regarding the EPA's development of NSPS and emission guidelines for EGUs and offered consultation. A consultation/outreach meeting was held on May 23, 2011, with the Forest County Potawatomi Community, the Fond du Lac Band of Lake Superior Chippewa Reservation, and the Leech Lake Band of Ojibwe. Other tribes participated in the call for information gathering purposes. In this meeting, the EPA provided background information on the GHG emission standards to be developed and a summary of issues being explored by the Agency. Tribes suggested that the EPA consider expanding coverage of the GHG standards to include combustion turbines, lowering the 250 MMBtu per hour heat input threshold so as to capture more EGUs, and including credit for use of renewables. The tribes were also interested in the scope of the emissions averaging being considered by the Agency (e.g., over what time period, across what units). In addition, the EPA held a series of listening sessions on this proposed action. 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.

While formulating the provisions of this proposed regulation, the EPA also considered the input provided in the over 2.5 million public comments on the April 13, 2012 proposed rule (77 FR 22392).

The EPA will also hold additional meetings with tribal environmental staff to inform them of the content of this proposal as well as provide additional consultation with tribal elected officials where it is appropriate. We specifically solicit additional comment on this proposed rule from tribal officials.

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 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 EO 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. This proposed action is not anticipated to have notable impacts on emissions, costs or energy supply decisions for the affected electric utility industry.

I. National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs the EPA to use Voluntary Census Standards in their 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 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: D5287–08 (Standard Practice for Automatic Sampling of Gaseous Fuels), D4057–06 (Standard Practice for Manual Sampling of Petroleum and Petroleum Products), and D4177–95(2010) (Standard Practice for Automatic Sampling of Petroleum and Petroleum Products). The EPA is proposing use of Appendices 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 new fossil fuel-fired EGUs 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 increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low-income or indigenous populations.

XIII. 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

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 70

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 71

Environmental Protection, Administrative practice and procedure, Air pollution control, Reporting and recordkeeping requirements.

40 CFR Part 98

Environmental protection, Greenhouse gases and monitoring, Reporting and recordkeeping requirements.

Dated: September 20, 2013.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 60, 70, 71, and 98 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.*

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units

■ 2. Section 60.46Da is added to read as follows:

§ 60.46Da Standards for carbon dioxide (CO_2).

(a) Your affected facility is subject to this section if construction commenced after [DATE OF PUBLICATION IN THE **FEDERAL REGISTER**], and the affected facility meets the conditions specified in paragraphs (a)(1) and (a)(2) of this section, except as specified in paragraph (b) of this section.

(1) The affected facility combusts fossil fuel for more than 10.0 percent of the heat input during any 3 consecutive calendar years.

(2) The affected facility supplies more than one-third of its potential electric output and more than 219,000 MWh net-electric output to a utility power distribution system for sale on an annual basis.

(b) The following EGUs are not subject to this section:

(1) The proposed Wolverine EGU project described in Permit to Install No. 317–07 issued by the Michigan Department of Environmental Quality, Air Quality Division, effective June 29, 2011 (as revised July 12, 2011).

(2) The proposed Washington County EGU project described in Air Quality Permit No. 4911–303–0051–P–01–0 issued by the Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, effective April 8, 2010, provided that construction had not commenced for NSPS purposes as of [DATE OF PUBLICATION IN THE **FEDERAL REGISTER**].

(3) The proposed Holcomb EGU project described in Air Emission Source Construction Permit 0550023 issued by the Kansas Department of Health and Environment, Division of Environment, effective December 16, 2010, provided that construction had not commenced for NSPS purposes as of [DATE OF PUBLICATION IN THE **FEDERAL REGISTER**].

(c) As owner or operator of an affected facility subject to this section, you shall not cause to be discharged into the atmosphere from the affected facility any gases that contain CO_2 in excess of the emissions limitation specified in either paragraphs (c)(1) or (c)(2) of this section.

(1) 500 kilograms (kg) of CO_2 per megawatt-hour (MWh) of gross energy output (1,100 lb CO_2/MWh) on a 12-operating month rolling average basis; or

(2) 480 kg of CO_2 per MWh of gross energy output (1,050 lb CO_2/MWh) on an 84-operating month rolling average basis.

(d) You must make compliance determinations at the end of each operating month, as provided in

paragraphs (d)(1) and (d)(2) of this section. For the purpose of this section, operating month means a calendar month during which any fossil fuel is combusted in the affected facility.

(1) If you elect to comply with the CO_2 emissions limitation in paragraph (c)(1) of this section, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected facility at the end of each 12-operating month period that includes, as the last month, the month for which you are determining compliance.

(2) If you elect to comply with the CO_2 emissions limitation in paragraph (c)(2) of this section, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected facility at the end of each 84-operating month period that includes, as the last month, the month for which you are determining compliance.

(e) You must conduct an initial compliance determination with the CO_2 emissions limitation for your affected facility within 30 days after accumulating the required number of operating months for the compliance period with which you have elected to comply (i.e., 12-operating months or 84-operating months). The first operating month included in this compliance period is the month in which emissions reporting is required to begin under § 75.64(a) of this chapter.

(f) You must monitor and collect data to demonstrate compliance with the CO_2 emissions limitation according to the requirements in paragraphs (f)(1) through (4) of this section.

(1) You must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter.

(2) You must measure the hourly CO_2 mass emissions from each affected facility using the procedures in paragraphs (f)(2)(i) through (vii) of this section, except as provided in paragraph (f)(3) of this section.

(i) You must install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record CO_2 concentrations in your affected facility's exhaust gases that are emitted to the atmosphere and an exhaust gas flow rate monitoring system according to § 75.10(a)(3)(i) of this chapter. If you measure CO_2 concentration on a dry basis, you 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 used to determine the CO_2 mass emissions, you 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) You 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, you must make measurements of the diameter at three or more distinct locations and average the results. For rectangular stacks or ducts, you must make measurements of 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, you must repeat these measurements at the new location.

(iv) You can only use unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions from the affected facility; you 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 you choose 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, you must use a calibrated Type-S pitot tube or pitot tube assembly. You must not use the default Type-S pitot tube coefficient.

(vi) If two or more affected facilities share a common exhaust gas stack and are subject to the same CO_2 emissions limitation in paragraph (c) of this section, you may monitor the hourly CO_2 mass emissions at the common exhaust gas stack rather than monitoring each affected facility separately.

(vii) If the exhaust gases from the affected facilities are emitted to the atmosphere through multiple stacks (or if the exhaust gases are routed to a common stack through multiple ducts and you choose to monitor in the ducts), you 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.

(3) As an alternative to complying with paragraph (f)(2) of this section, for affected facilities that do not combust any solid fuel, you 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 specified in paragraphs (f)(3)(i) and (f)(3)(ii) of this section.

(i) You 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) You 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 you 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) You must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the gross electric output from the affected facility, and you must meet the requirements specified in paragraphs (f)(4)(i) and (ii) of this section, as applicable.

(i) If your affected facility is a combined heat and power unit as defined in § 60.42Da, you must also install, calibrate, maintain, and operate meters to continuously determine and record the total useful recovered thermal energy. For process steam applications, you must install, calibrate, maintain, and operate meters to continuously determine and record steam flow rate, temperature, and pressure. If your affected facility has a direct mechanical drive application, you must submit a plan to the Administrator or delegated authority for approval of how gross energy output will be determined. Your plan shall ensure that you install, calibrate, maintain, and operate meters to continuously determine and record each component of the determination.

(ii) If two or more affected facilities have steam generating units that serve a common electric generator, you must apportion the combined hourly gross electric output to each individual affected facility using a plan approved by the Administrator (e.g., using steam load or heat input to each affected facility). Your plan shall ensure that you install, calibrate, maintain, and operate meters to continuously determine and record each component of the determination.

(g) You must demonstrate compliance with the CO_2 emissions limitation using the procedures specified in paragraphs (g)(1) and (2) of this section.

(1) You must calculate the CO_2 mass emissions rate for your affected facility using the calculation procedures in paragraphs (g)(1)(i) through (v) of this section with the hourly CO_2 mass emissions and gross energy output data determined and recorded according to the procedures in paragraph (f) of this section for each operating hour in the applicable compliance period (i.e., 12-

operating months or 84-operating months).

(i) You must only use operating hours in the compliance period for which you have valid data for all the parameters you use to determine the hourly CO_2 mass emissions and gross output data. You must not use operating hours which use the substitute data provisions of part 75 of this chapter for any of the parameters in the calculation. For the compliance determination calculation, you must obtain valid hourly values for a minimum of 95 percent of the operating hours in the applicable compliance period.

(ii) You must calculate the total CO_2 mass emissions by summing all of the valid hourly CO_2 mass emissions values for the applicable compliance period. If exhaust gases from the affected facility are emitted to the atmosphere through multiple stacks or ducts, you must calculate the total CO_2 mass emissions for the affected facility by summing the total CO_2 mass emissions from each of the individual stacks or ducts.

(iii) For each operating hour of the compliance period used in paragraph (g)(1)(ii) of this section to calculate the total CO_2 mass emissions, you must determine the affected facility's corresponding hourly gross energy output using the appropriate definitions in § 60.42Da and paragraph (k) of this section and using the procedure specified in paragraphs (g)(3)(iii)(A) through (D) of this section.

(A) Calculate P_{gross} for your affected facility using the following equation:

$$P_{gross} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW}}{T} + 0.75 \times [\,(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\,]$$

Where: a

P_{gross} = Gross energy output of your affected facility in megawatt-hours in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected facility's integrated equipment that provides electricity or mechanical energy to the affected facility or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. This term is not applicable to IGCC facilities.

$(Pt)_{PS}$ = Useful thermal energy output of steam measured relative to ISO conditions that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected facility. This term is calculated using the equation specified in paragraph (g)(3)(iii)(B) of this section in MWh.

$(Pt)_{HR}$ = Hourly useful thermal energy output measured relative to ISO conditions from heat recovery that is used for applications other than steam generation or performance enhancement of the affected facility in MWh.

$(Pt)_{IE}$ = Useful thermal energy output relative to ISO conditions from any integrated equipment that provides thermal energy to the affected facility or auxiliary equipment in MWh.

T = Electric Transmission and Distribution Factor.

T = 0.95 for a combined heat and power affected facility where at least on an annual basis 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 energy output on a rolling 3 year basis.

T = 1.0 for all other affected facilities.

(B) If applicable to your affected facility, calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{3.6 \times 10^9}$$

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions in Joules per kilogram (J/kg) (or Btu/lb).

3.6×10^9 = Conversion factor (J/MWh) (or 3.413×10^6 Btu/MWh).

(C) For an operating hour in which there is no gross electric load, but there is mechanical or useful thermal output, you must still determine the gross energy output for that hour. In addition, for an operating hour in which there is no useful output, you must still determine the hourly gross CO_2 emissions for that hour.

(D) If hourly CO_2 mass emissions are determined for a common stack, you must determine the hourly gross energy output (electric, thermal, and/or mechanical, as applicable) by summing the hourly loads for the individual affected facility and you must express the operating time as ''stack operating hours'' (as defined in § 72.2 of this chapter).

(iv) You must calculate the total gross energy output by summing the hourly gross energy output values for the affected facility determined from paragraph (g)(1)(iii) of this section for all of the operating hours in the applicable compliance period.

(v) You must calculate the CO_2 mass emissions rate for the applicable compliance period interval by dividing the total CO_2 mass emissions value from paragraph (g)(1)(ii) of this section by the total gross energy output value from paragraph (g)(1)(iv) of this section.

(2) You must determine compliance with the CO_2 emissions limitation in paragraph (c) of this section is determined as specified in paragraphs (g)(2)(i) and (ii) of this section using the CO_2 mass emissions rate for your affected facility that you determined in paragraph (g)(1) of this section.

(i) If the CO_2 mass emissions rate for your affected facility is less than or equal to the CO_2 emissions limitation applicable to your affected facility, then your affected facility is in compliance with the CO_2 emissions limitation. If you attain compliance with the CO_2 emissions limitation at a common stack for two or more affected facilities subject to the same CO_2 emissions limitation, each affected facility sharing the stack is in compliance with the CO_2 emissions limitation.

(ii) If the CO_2 mass emissions rate for the affected facility is greater than the CO_2 emissions limitation in paragraph (c) of this section applicable to the affected facility, then the affected facility has excess CO_2 emissions.

(h) You must prepare and submit notifications and reports according to paragraphs (h)(1) through (4) of this section.

(1) You must prepare and submit the notifications in §§ 60.7(a)(1) and (a)(3) and 60.19, as applicable to your affected facility.

(2) You must prepare and submit notifications in § 75.61 of this chapter, as applicable to your affected facility.

(3) You must submit electronic quarterly reports according to the requirements specified in paragraphs (h)(3)(i) through (iii) of this section.

(i) Initially, after you have accumulated the required number of operating months for the CO_2 emission limitation compliance period that you have chosen to comply with (i.e., 12-operating months or 84-operating months), you must submit a report for

the calendar quarter that includes the final (12th- or 84th) operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter no later than 30 days after the end of the quarter.

(ii) In each quarterly report you must include the information in paragraphs (h)(3)(ii)(A) through (E) of this section.

(A) The CO_2 emission limitation compliance period with which you have chosen to comply.

(B) Any months in the calendar quarter that you are not counting as operating months.

(C) For each operating month in the calendar quarter, the corresponding average CO_2 mass emissions rate for the applicable compliance period interval that you determined according to paragraph (g) of this section.

(D) The percentage of valid CO_2 mass emission rates in each compliance period (i.e., the total number of valid CO_2 mass emission rates in that period divided by the total number of operating hours in that period, multiplied by 100 percent).

(E) Any operating months in the calendar quarter with excess CO_2 emissions.

(iii) In the final quarterly report of each calendar year you must include the following:

(A) Net electric output sold to an electric grid over the calendar year; and

(B) The potential electric output of the facility.

(iv) You must submit each electronic report using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the EPA Office of Atmospheric Programs.

(4) You must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(5) If your affected unit uses geologic sequestration to meet the applicable emissions limit, you must report in accordance with the requirements of 40 CFR Part 98, subpart PP and either:

(i) if injection occurs onsite, report in accordance with the requirements of 40 CFR Part 98, subpart RR, or

(ii) if injection occurs offsite, transfer the captured CO_2 to a facility or facilities that reports in accordance with the requirements of 40 CFR Part 98, subpart RR.

(i) For each affected electric utility stream generating unit, you must maintain records according to paragraphs (i)(1) through (i)(8) of this section.

(1) You must comply with the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(2) You must maintain records of the calculations you performed to determine the total CO_2 mass emissions for each operating month, and the averages for each compliance period interval (i.e., 12-operating months or 84-operating months, as applicable to the CO_2 emissions limitations).

(3) You must maintain records of the applicable data recorded and calculations performed that you used to determine the gross energy output for each operating month.

(4) You must maintain records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(5) You must maintain records of the calculations you performed to assess compliance with each applicable CO_2 emissions limitation in paragraph (c) of this section.

(6) Your records must be in a form suitable and readily available for expeditious review.

(7) You must maintain each record for 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record except those records required to demonstrate compliance with an 84-operating month compliance period. You must maintain records required to demonstrate compliance with an 84-operating month compliance period for at least 10 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(8) You 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. You may maintain the records off site and electronically for the remaining year(s) as required by this subpart.

(j) *PSD and Title V Thresholds for Greenhouse Gases.*

(1) For purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from new affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from new affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from new affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 70.2.

(4) For purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from new affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 71.2.

(k) For purposes of this section, the following definitions apply:

Gross energy output means:

(i) Except as provided under paragraph (ii) of this definition, for electric utility steam generating units, the gross electric or mechanical output from the affected facility (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expanders) minus any electricity used to power the feedwater pumps plus 75 percent of the useful thermal output measured relative to ISO 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);

(ii) For electric utility steam generating unit 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 at least 20.0 percent of the total gross energy output consists of thermal output on a rolling 3 year basis, the gross electric or mechanical output from the affected facility (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expanders) minus any electricity used to power the feedwater pumps, that difference divided by 0.95, plus 75 percent of the useful thermal output measured relative to ISO 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);

(iii) Except as provided under paragraph (ii) of this definition, for a IGCC electric utility generating unit, the gross electric or mechanical output from the affected facility (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expanders) plus 75 percent of the useful

thermal output measured relative to ISO 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);

(iv) For IGCC electric utility generating unit 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 at least 20.0 percent of the total gross energy output consists of thermal output on a rolling 3 year basis, the gross electric or mechanical output from the affected facility (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expanders) divided by 0.95, plus 75 percent of the useful thermal output measured relative to ISO 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);

IGCC facility is an integrated gasification combined cycle electric utility steam generating unit, which means an electric utility 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 facility during operation.

Net-electric output means:

(i) Except as provided under paragraph (ii) of this definition, the gross electric sales to the utility power distribution system minus purchased power on a calendar year basis, or

(ii) 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 at least 20.0 percent of the total gross energy output consists of thermal output, 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.

Potential electric output means:

(i) Either 33 percent or the design net electric output efficiency, at the election of the owner/operator of the affected facility,

(ii) Multiplied by the maximum design heat input capacity of the steam generating unit,

(iii) Divided by 3,413 Btu/KWh,

(iv) Divided by 1,000 kWh/MWh, and

(v) Multiplied by 8,760 h/yr.

(vi) For example, 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 electric output capacity.

Steam generating unit means 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 boiler or auxiliary equipment.

Subpart KKKK—Standards of Performance for Stationary Combustion Turbines

■ 3. Section 60.4305 is amended by adding paragraph (c) to read as follows:

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

* * * * *

(c) For purposes of regulation of greenhouse gases, the applicable provisions of this subpart affect your stationary combustion turbine if it meets the applicability conditions in paragraphs (c)(1) through (c)(5) of this section.

(1) Commenced construction after [DATE OF PUBLICATION IN THE **FEDERAL REGISTER**];

(2) Has a design heat input to the turbine engine greater than 73 MW (250 MMBtu/h);

(3) Combusts fossil fuel for more than 10.0 percent of the heat input during any 3 consecutive calendar years.

(4) Combusts over 90% natural gas on a heat input basis on a 3 year rolling average basis; and

(5) 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.

■ 4. Section 60.4315 is revised to read as follows:

§ 60.4315 What pollutants are regulated by this subpart?

(a) The pollutants regulated by this subpart are nitrogen oxides (NO_X), sulfur dioxide (SO_2), and greenhouse gases.

(b)(1) The greenhouse gases regulated by this subpart consist of carbon dioxide (CO_2).

(2) *PSD and Title V Thresholds for Greenhouse Gases.*

(i) For purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected stationary combustion turbine, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(ii) For purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected stationary combustion turbines, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(iii) For purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected stationary combustion turbines, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 70.2.

(iv) For purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected stationary combustion turbines, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 71.2.

■ 5. Section 60.4326 is added to read as follows:

§ 60.4326 What CO_2 emissions standard must I meet?

You must not discharge from your affected stationary combustion turbine into the atmosphere any gases that contain CO_2 in excess of the applicable CO_2 emissions standard specified in Table 2 of this subpart.

■ 6. Section 60.4333 is amended by adding paragraph (c) to read as follows:

§ 60.4333 What are my general requirements for complying with this subpart?

* * * * *

(c) If you own or operate an affected stationary combustion turbine subject to a CO_2 emissions standard in § 60.4326, you must make compliance determinations on a 12-operating month rolling average basis, and you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected stationary

combustion turbine at the end of each 12-operating month period.

■ 7. Section 60.4373 is added under undesignated center heading ''Monitoring'' to read as follows:

§ 60.4373 How do I monitor and collect data to demonstrate compliance with my CO_2 emissions standard using a CO_2 CEMS?

(a) You must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter.

(b) You must measure the hourly CO_2 mass emissions from each affected stationary combustion turbine using the procedures in paragraphs (b)(1) through (5) of this section, except as provided in paragraph (c) of this section.

(1) You must install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record CO_2 concentrations in the stationary combustion turbine 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 you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter.

(2) For each monitoring system that you use to determine the CO_2 mass emissions, you 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.

(3) You 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, you must make measure of the diameter at three or more distinct locations and average the results. For rectangular stacks or ducts, you 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, you must repeat these measurements at the new location.

(4) You must use unadjusted exhaust gas volumetric flow rates only to determine the hourly CO_2 mass emissions from the affected stationary combustion turbine; you 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.

(5) If you chose 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, you must use a calibrated Type-S pitot tube or pitot tube assembly. You must not use the default Type-S pitot tube coefficient.

(c) As an alternative to complying with paragraph (b) of this section, you 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 specified in paragraphs (c)(1) and (2) of this section.

(1) You 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.

(2) You 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 you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(d) You must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the gross electric output from the affected stationary combustion turbine. If the affected stationary combustion turbine is a CHP stationary combustion turbine, you must also install, calibrate, maintain, and operate meters to continuously determine and record the total useful recovered thermal energy. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record steam flow rate, temperature, and pressure. If the affected stationary combustion turbine has a direct mechanical drive application, you must submit a plan to the Administrator or delegated authority for approval of how gross energy output will be determined. Your plan shall ensure that you install, calibrate, maintain, and operate meters to continuously determine and record each component of the determination.

(e) If two or more affected stationary combustion turbines serve a common electric generator, you must apportion the combined hourly gross output to the individual stationary combustion turbines using a plan approved by the Administrator (e.g., using steam load or heat input to each affected stationary combustion turbine). Your plan shall ensure that you install, calibrate, maintain, and operate meters to continuously determine and record each component of the determination.

(f) In accordance with § 60.13(g), if two or more stationary combustion turbines that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack and are subject to the same emissions standard under § 60.4326, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each stationary combustion turbine separately. If you choose this option, the hourly gross load (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual stationary combustion turbines and you must express the operating time as ''stack operating hours'' (as defined in § 72.2 of this chapter). If you attain compliance with the applicable emissions standard in § 60.4326 at the common stack, each stationary combustion turbine sharing the stack is in compliance.

(g) In accordance with § 60.13(g), if the exhaust gases from a stationary combustion turbine that implements the continuous emission monitoring provisions in paragraph (b) 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 chose to monitor in the ducts), you 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, you determine compliance with the applicable emissions standard in § 60.4326 by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross output for the unit.

■ 8. Section 60.4374 is added under undesignated center heading ''Monitoring'' to read as follows:

§ 60.4374 How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) You must calculate the CO_2 mass emissions rate for your affected stationary combustion turbine by using the hourly CO_2 mass emissions and total gross output data determined and recorded according to the procedures in § 60.4373 for the compliance period for the CO_2 emissions standard applicable to the affected stationary combustion turbine, and the calculation procedures in paragraphs (a)(1) through (a)(5) of this section.

(1) You must only use operating hours in the compliance period for the compliance determination calculation for which you obtained valid data for all

parameters you used to determine the hourly CO_2 mass emissions and gross output data, are used for the compliance determination calculation. You must not include operating hours in which you used the substitute data provisions of part 75 of this chapter for any of the parameters in the calculation. For the compliance determination calculation, you must obtain valid hourly CO_2 mass emission values for a minimum of 95 percent of the operating hours in the compliance period.

(2) You must calculate the total CO_2 mass emissions by summing the hourly CO_2 mass emissions values for the affected stationary combustion turbine determined to be valid according to the conditions specified in paragraph (a)(1) of this section for all of the operating hours in the applicable compliance period.

(3) For each operating hour of the compliance period used in paragraph (a)(2) of this section to calculate the total CO_2 mass emissions, you must determine the affected stationary combustion turbine's corresponding hourly gross output (P_{gross}) by applying the appropriate definitions in §§ 60.4420 and 60.4421 of this subpart and according to the procedures specified in paragraphs (a)(3)(i) and (iv) of this section.

(i) Calculate P_{gross} for your affected stationary combustion turbine using the following equation:

$$P_{gross} = \frac{(Pe)_{CT} + (Pe)_{ST} + (Pe)_{IE}}{T} + 0.75 \times [(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}]$$

Where:

P_{gross} = Gross energy output of your affected stationary combustion turbine in megawatt-hours in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbines in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected stationary combustion turbine's integrated equipment that provides electricity to the affected facility or auxiliary equipment in MWh.

$(Pt)_{PS}$ = Useful thermal energy output of steam relative to ISO conditions that is used for applications that do not generate additional electricity, produce mechanical energy output, enhance the performance of the affected facility. Calculated using the equation specified in paragraph (a)(3)(ii) of this section in MWh.

$(Pt)_{HR}$ = Useful thermal energy output relative to ISO conditions from heat recovery that is used for applications other than steam generation or performance enhancement of the affected facility in MWh.

$(Pt)_{IE}$ = Useful thermal energy output relative to ISO conditions from any integrated equipment that provides input to the affected facility or auxiliary equipment in MWh.

T = Electric Transmission and Distribution Factor.

T = 0.95 for a CHP stationary combustion turbine where at least on an annual basis 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 energy output on a rolling 3 year basis.

T = 1.0 for all other affected stationary combustion turbines.

(ii) If applicable to your affected stationary combustion turbine, calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{3.6 \times 10^9}$$

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions in Joules per kilogram (J/kg) (or Btu/lb).

3.6×10^9 = Conversion factor (J/MWh) (or 3.413×10^6 Btu/MWh).

(iii) You must determine the hourly gross energy output for each operating hour in which there is no electric output, but there is mechanical output or useful thermal output. In addition you must determine the hourly gross CO_2 emissions for each operating hour in which there is no useful output.

(iv) In the case for which compliance is demonstrated according to § 60.4373(f) for affected stationary combustion turbines that vent to a common stack, then you must calculate the hourly gross energy output (electric, mechanical, and/or thermal, as applicable) by summing the hourly gross energy output you determined for each of your individual affected stationary combustion turbines that vent to the common stack; and you must express the operating time as ''stack operating hours'' (as defined in § 72.2 of this chapter).

(4) You must calculate the total gross output for the affected stationary combustion turbine's compliance period by summing the hourly gross output values for the affected stationary combustion turbine determined from paragraph (a)(2) of this section for all of the operating hours in the applicable compliance period.

(5) You must calculate the CO_2 mass emissions rate for the affected stationary combustion turbine by dividing the total CO_2 mass emissions value as calculated according to the requirements of paragraph (a)(2) of this section by the total gross output value as calculated according to the requirements of paragraph (a)(4) of this section.

(b) If the CO_2 mass emissions rate for the affected stationary combustion turbine determined according to the procedures specified in paragraph (a) of this section is less than or equal to the CO_2 emissions standard in Table 2 of this subpart applicable to the affected stationary combustion turbine, then your affected stationary combustion turbine is in compliance with the emissions standard. If the average CO_2 mass emissions rate is greater than the CO_2 emissions standard in Table 2 of this subpart applicable to the affected stationary combustion turbine, then your affected stationary combustion turbine has excess CO_2 emissions.

■ 9. Section 60.4375 is amended by revising the section heading to read as follows:

§ 60.4375 What reports must I submit to comply with my NO_X and SO_2 emissions limits?

* * * * *

■ 10. Section 60.4376 is added to read as follows:

§ 60.4376 What notifications and reports must I submit to comply with my CO_2 emissions standard?

(a)(1) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (a)(3) and 60.19, as applicable to your affected stationary combustion turbine.

(2) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable to your affected stationary combustion turbine.

(b) You must prepare and submit reports according to paragraphs (b)(1) through (d) of this section, as applicable.

(1) For stationary combustion turbines that are required, by § 60.4333(c), to conduct initial and on-going compliance determinations on a 12-operating month rolling average basis for the standard in § 60.4326, you must submit electronic quarterly reports as follows. After you

have accumulated the first 12-operating months for the affected stationary combustion turbine, you must submit a report for the calendar quarter that includes the 12th-operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report, you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (12th) operating month in a 12-operating month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate according to the requirements of § 60.4374. You must report the dates (month and year) of the 1st and 12th-operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter, you must identify each operating month in the calendar quarter with excess CO_2 emissions;

(iii) The percentage of valid CO_2 mass emission rates (as defined in § 60.4374) in each 12-operating month compliance period described in paragraph (b)(2)(i) of this section (i.e., the total number of valid CO_2 mass emission rates in that period divided by the total number of operating hours in that period, multiplied by 100 percent); and

(iv) The CO_2 emissions standard (as identified in Table 2 of this subpart) with which your affected stationary combustion turbine is complying.

(3) The final quarterly report of each calendar year must contain the following:

(i) Net electric output sold to an electric grid over the 4 quarters of the calendar year; and

(ii) The potential electric output of the stationary combustion turbine.

(c) You must submit all electronic reports required under paragraph (b) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of the EPA.

(d) You must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

■ 11. Section 60.4391 is added to read as follows:

§ 60.4391 What records must I maintain to comply with my CO_2 emissions limits?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b) You must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(c) You must keep records of the calculations you performed to determine the total CO_2 mass emissions for:

(1) Each operating month (for all affected units);

(2) Each compliance period, including, as applicable, each 12-operating month compliance period.

(d) You must keep records of the applicable data recorded and calculations performed that you used to determine your affected stationary combustion turbine's gross output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in § 60.4326.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

(h)(1) Your records must be in a form suitable and readily available for expeditious review.

(2) You must keep each record for 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record to demonstrate compliance with a 12-operating month emissions standard.

(3) You must keep 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. You may keep the records off site and electronically for the remaining year(s) as required by this subpart.

■ 12. Section 60.4395 is revised to read as follows:

§ 60.4395 When must I submit my reports?

All of your reports required under § 60.7(c) must be postmarked by the 30th day after the end of each 6-month period, except as specified in § 60.4376

■ 13. Section 60.4421 is added to read as follows:

§ 60.4421 What definitions with respect to CO_2 emissions apply to this subpart?

As used in this subpart:

Base load rating means 100 percent of the manufacturer's design heat input capacity of the combustion turbine engine at ISO conditions using the higher heating value of the fuel (heat input from duct burners is not included).

Excess emissions means a specified averaging period over which either:

(1) The CO_2 emissions rate of your affected stationary combustion turbine exceeds the applicable emissions standard in Table 2 of this subpart or § 60.4330; or

(2) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

Gross energy output means:

(1) The gross electric or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) or integrated equipment plus any useful thermal output measured relative to ISO conditions (except for GHG calculations in § 60.4374 as only 75 percent credit is given) 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 a CHP stationary combustion turbine where at least 20.0 percent of the total gross energy output consists of electric or direct mechanical output and at least 20.0 percent of the total gross energy output consists of useful thermal output on a rolling 3-year basis, the sum of the gross electric or direct mechanical output from both the combustion turbine engine and any associated steam turbine(s) divided by 0.95 plus any useful thermal output measured relative to ISO conditions (except for GHG calculations in § 60.4374 as only 75 percent credit is given) 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).

Net-electric output means:

(1) The gross electric sales to the utility power distribution system minus purchased power on a 3 calendar year rolling average basis; or

(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 at least 20.0 percent of the total gross energy output consists of useful thermal output on a 3 calendar year rolling average basis, the gross electric sales to the utility power distribution system minus purchased power of the thermal

host facility or facilities on a three calendar year rolling average basis.

Operating month means a calendar month during which any fuel is combusted in the affected stationary combustion turbine.

Potential electric output means 33 percent or the design electric output efficiency on a net output basis (at the election of the owner/operator of the affected facility) multiplied by the base load rating (expressed in MMBtu/h) of the stationary combustion turbine, multiplied by 10^6 Btu/MMBtu, 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 stationary combustion turbine with a 100 MW (341 MMBtu/h) fossil-fuel heat input capacity would have a 310,000 MWh 12-month potential electric output capacity).

Stationary combustion turbine means all equipment, including but not limited to the combustion turbine engine, the fuel, air, lubrication and exhaust gas systems, control systems, heat recovery system, steam turbine, fuel compressor, heater, and/or pump, post-combustion emission control technology, and any ancillary components and sub-components 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.

■ 14. Table 2 to Subpart KKKK of Part 60 is added to read as follows:

TABLE 2 TO SUBPART KKKK OF PART 60—CARBON DIOXIDE EMISSION LIMITS FOR STATIONARY COMBUSTION TURBINES

[**Note:** all numerical values have a minimum of 2 significant figures]

Affected stationary combustion turbine	CO_2 Emission standard
Stationary combustion turbine that has a design heat input to the turbine engine of greater than 250 MW (850MMBtu/h).	450 kilograms (kg) of CO_2 per megawatt-hour (MWh) of gross output (1,000 lb/MWh) on a 12-operating month rolling average.
Stationary combustion turbine that has a design heat input to the turbine engine greater than 73 MW (250 MMBtu/h) and equal to or less than 250 MW (850MMBtu/h).	500 kg of CO_2 per MWh of gross output (1,100 lb CO_2/MWh) on a 12-operating month rolling average.

■ 15. Table 3 to Subpart KKKK of Part 60 is added to read as follows:

TABLE 3 TO SUBPART KKKK OF PART 60—APPLICABILITY OF SUBPART A GENERAL PROVISIONS TO STATIONARY COMBUSTION TURBINE CO_2 EMISSIONS STANDARDS IN SUBPART KKKK

General provisions citation	Subject of citation	Applies to subpart KKKK	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes.	
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes.	
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notification in § 60.7(a)(1) and (a)(3).
§ 60.8	Performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13	Monitoring requirements	Yes.	
§ 60.14	Modification	No.	
§ 60.15	Reconstruction	No.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes.	

■ 16. Part 60 is amended by adding subpart TTTT to read as follows:

Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units

Sec.

Applicability

60.5508 What is the purpose of this subpart?

60.5509 Am I subject to this subpart?

Emission Standards

60.5515 What greenhouse gases are regulated by this subpart?

60.5520 What CO_2 emissions standard must I meet?

General Compliance Requirements

60.5525 What are my general requirements for complying with this subpart?

60.5530 Affirmative defense for violation of emission standards during malfunction

Monitoring and Compliance Determination Procedures

60.5535 How do I monitor and collect data to demonstrate compliance?

60.5540 How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

Notifications, Reports, and Records

60.5550 What notifications must I submit and when?
60.5555 What reports must I submit and when?
60.5560 What records must I maintain?
60.5565 In what form and how long must I keep my records?

Other Requirements and Information

60.5570 What parts of the General Provisions apply to my affected facility?
60.5575 Who implements and enforces this subpart?
60.5580 What definitions apply to this subpart?

Applicability

§ 60.5508 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit, IGCC, or a stationary combustion turbine that commences construction after [DATE OF PUBLICATION IN THE **FEDERAL REGISTER**].

§ 60.5509 Am I subject to this subpart?

(a) Except as provided for in paragraph (b) of this section, the subpart applies to any steam generating unit, IGCC, or stationary combustion turbine that commences construction after [DATE OF PUBLICATION IN THE **FEDERAL REGISTER**] that meets the relevant applicability conditions in paragraphs (a)(1) and (a)(2) of this section.

(1) A steam generating unit or IGCC that has a design heat input greater than 73 MW (250MMBtu/h) heat input of fossil fuel (either alone or in combination with any other fuel), combusts fossil fuel for more than 10.0 percent of the average annual heat input during a 3 year rolling average basis, and 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-electric output to a utility distribution system on an annual basis.

(2) A stationary combustion turbine that has a design heat input to the turbine engine greater than 73 MW (250 MMBtu/h), combusts fossil fuel for more than 10.0 percent of the average annual heat input during a 3 year rolling average basis, combusts over 90% natural gas on a heat input basis on a 3 year rolling average basis, and 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.

(b) You are not subject to the requirements of this subpart if your affected facility meets any one of the conditions specified in paragraphs (b)(1) through (b)(5) of this section.

(1) The proposed Wolverine EGU project described in Permit to Install No. 317–07 issued by the Michigan Department of Environmental Quality, Air Quality Division, effective June 29, 2011 (as revised July 12, 2011).

(2) The proposed Washington County EGU project described in Air Quality Permit No. 4911–303–0051–P–01–0 issued by the Georgia Department of Natural Resources, Environmental Protection Division, Air Protection Branch, effective April 8, 2010, provided that construction had not commenced for NSPS purposes as of [DATE OF PUBLICATION IN THE **FEDERAL REGISTER**].

(3) The proposed Holcomb EGU project described in Air Emission Source Construction Permit 0550023 issued by the Kansas Department of Health and Environment, Division of Environment, effective December 16, 2010, provided that construction had not commenced for NSPS purposes as of [DATE OF PUBLICATION IN THE **FEDERAL REGISTER**].

(4) Your affected facility is a municipal waste combustor unit that is subject to subpart Eb of this part.

(5) Your affected facility is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

Emission Standards

§ 60.5515 What greenhouse gases are regulated by this subpart?

(a) The greenhouse gas regulated by this subpart is carbon dioxide (CO_2).

(b) *PSD and Title V Thresholds for Greenhouse Gases.*

(1) For purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any SIP approved by the EPA that is interpreted to incorporate, or specifically incorporates, 40 CFR 51.166(b)(48).

(2) For purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the ''pollutant that is subject to the standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 52.21(b)(49).

(3) For purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 70.2.

(4) For purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the ''pollutant that is subject to any standard promulgated under section 111 of the Act'' shall be considered to be the pollutant that otherwise is ''subject to regulation'' as defined in 40 CFR 71.2.

§ 60.5520 What CO_2 emissions standard must I meet?

For each affected facility subject to this subpart, you must not discharge from the affected facility stack into the atmosphere any gases that contain CO_2 in excess of the applicable CO_2 emissions standard specified in Table 1 of this subpart.

General Compliance Requirements

§ 60.5525 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission standards in this subpart that apply to your affected facility at all times. However, you must make a compliance determination only at the end of the applicable operating month, as provided in paragraphs (a)(1) and (2) of this section.

(1) For each affected facility subject to a CO_2 emissions standard based on a 12-operating month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected facility at the end of each 12-operating month period.

(2) For each affected facility subject to a CO_2 emissions standard based on an 84-operating month rolling average, you must determine compliance monthly by calculating the average CO_2 emissions rate for the affected facility at the end of each 84-operating month period.

(b) At all times you must operate and maintain each affected facility, including associated equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practice. The Administrator will determine if you are using consistent operation and maintenance procedures based on information available to the Administrator that may include, but is not limited to, fuel use records, monitoring results, review of operation and maintenance procedures and

records, review of reports required by this subpart, and inspection of the facility.

(c) You must conduct an initial compliance determination for your affected facility for the applicable emissions standard in § 60.5520, according to the requirements in this subpart, within 30 days after the end of the initial compliance period for the CO_2 emissions standards applicable to your affected facility (i.e., 12-operating months or 84-operating months). The first operating month included in this compliance period is the month in which emissions reporting is required to begin under § 75.64(a) of this chapter.

§ 60.5530 Affirmative defense for violation of emission standards during malfunction.

In response to an action to enforce the standards set forth in § 60.5520, you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at 40 CFR 60.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices;

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for;

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(2) Repairs were made as expeditiously as possible when the violation occurred;

(3) The frequency, amount and duration of the violation (including any bypass) were minimized to the maximum extent practicable;

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health;

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices;

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs;

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. This affirmative defense report is due after the initial occurrence of the exceedance of the standard in § 60.5520, and on the same quarterly reporting schedule as in § 60.5555 (which may be the end of any applicable averaging period). If such quarterly report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the following quarterly report required in § 60.5555(a).

Monitoring and Compliance Determination Procedures

§ 60.5535 How do I monitor and collect data to demonstrate compliance?

(a) You must prepare a monitoring plan in accordance with the applicable provisions in § 75.53(g) and (h) of this chapter.

(b) You must measure the hourly CO_2 mass emissions from each affected facility using the procedures in paragraphs (b)(1) through (5) of this section, except as provided in paragraph (c) of this section.

(1) You must install, certify, operate, maintain, and calibrate a CO_2 continuous emission monitoring system (CEMS) to directly measure and record CO_2 concentrations in the affected facility 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 you measure CO_2 concentration on a dry basis, you must also install, certify, operate, maintain, and calibrate a continuous moisture monitoring system, according to § 75.11(b) of this chapter.

(2) For each monitoring system you use to determine the CO_2 mass emissions, you 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.

(3) You 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, you must measure the diameter at three or more distinct locations and average the results. For rectangular stacks or ducts, you 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, you must repeat these measurements at the new location.

(4) You must use only unadjusted exhaust gas volumetric flow rates to determine the hourly CO_2 mass emissions from the affected facility; you 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.

(5) If you choose 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, you must use a calibrated Type-S pitot tube or pitot tube assembly. You must not use the default Type-S pitot tube coefficient.

(c) If your affected facility exclusively combusts liquid fuel and/or gaseous fuel as an alternative to complying with paragraph (b) of this section, you 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 (c)(1) and (2) of this section.

(1) You 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.

(2) You 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 you may use these F_c values in the emissions calculations instead of using the default F_c values in the Equation G–4 nomenclature.

(d) You must install, calibrate, maintain, and operate a sufficient number of watt meters to continuously measure and record the gross electric output from the affected facility. If the affected facility is a CHP facility, you must also install, calibrate, maintain, and operate meters to continuously determine and record the total useful recovered thermal energy. For process steam applications, you will need to install, calibrate, maintain, and operate meters to continuously determine and record steam flow rate, temperature, and pressure. If the affected facility has a direct mechanical drive application, you must submit a plan to the Administrator or delegated authority for approval of how gross energy output will be determined. Your plan shall ensure that you install, calibrate, maintain, and operate meters to continuously determine and record each component of the determination.

(e) If two or more affected facilities serve a common electric generator, you must apportion the combined hourly gross output to the individual affected facilities using a plan approved by the Administrator (e.g., using steam load or heat input to each affected EGU). Your plan shall ensure that you install, calibrate, maintain, and operate meters to continuously determine and record each component of the determination.

(f) In accordance with § 60.13(g), if two or more affected facilities that implement the continuous emission monitoring provisions in paragraph (b) of this section share a common exhaust gas stack and are subject to the same emissions standard under § 60.5520, you may monitor the hourly CO_2 mass emissions at the common stack in lieu of monitoring each EGU separately. If you choose this option, the hourly gross load (electric, thermal, and/or mechanical, as applicable) must be the sum of the hourly loads for the individual affected facility and you must express the operating time as ''stack operating hours'' (as defined in § 72.2 of this chapter). If you attain compliance with the applicable emissions standard in § 60.5520 at the common stack, each affected facility sharing the stack is in compliance.

(g) In accordance with § 60.13(g), if the exhaust gases from an affected facility that implements the continuous emission monitoring provisions in paragraph (b) 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), you 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, you must determine compliance with the applicable emissions standard in § 60.5520 by summing the CO_2 mass emissions measured at the individual stacks or ducts and dividing by the total gross output for the affected facility.

§ 60.5540 How do I demonstrate compliance with my CO_2 emissions standard and determine excess emissions?

(a) You must calculate the CO_2 mass emissions rate for your affected facility by using the hourly CO_2 mass emissions and total gross output data determined and recorded according to the procedures in § 60.5535 for each operating hour in the compliance period for the CO_2 emissions standard applicable to the affected facility (i.e., 12- or 84-operating month rolling average period), and the calculation procedures in paragraphs (a)(1) through (a)(5) of this section.

(1) You can only use operating hours in the compliance period for the compliance determination calculation if valid data are obtained for all parameters you used to determine the hourly CO_2 mass emissions and the gross output data are used for the compliance determination calculation. You must not include operating hours in which you used the substitute data provisions of part 75 of this chapter for any of those parameters in the calculation. For the compliance determination calculation, you must obtain valid hourly CO_2 mass emission values for a minimum of 95 percent of the operating hours in the compliance period for the CO_2 emissions standard applicable to the affected facility.

(2) You must calculate the total CO_2 mass emissions by summing the valid hourly CO_2 mass emissions values for all of the operating hours in the applicable compliance period.

(3) For each operating hour of the compliance period that you used in paragraph (a)(2) of this section to calculate the total CO_2 mass emissions, you must determine the affected facility's corresponding hourly gross output according to the procedures in paragraphs (a)(3)(i) and (ii) of this section, as appropriate for the type of affected facility. For an operating hour in which there is no gross electric load, but there is mechanical or useful thermal output, you must still determine the gross output for that hour. In addition, for operating hours in which there is no useful output, you still need to determine the CO_2 emissions for that hour.

(i) Calculate P_{gross} for your affected facility using the following equation:

$$P_{gross} = \frac{(Pe)_{ST} + (Pe)_{CT} + (Pe)_{IE} - (Pe)_{FW}}{T} + 0.75 \times [\,(Pt)_{PS} + (Pt)_{HR} + (Pt)_{IE}\,]$$

Where: a

P_{gross} = Gross energy output of your affected facility in megawatt-hours in MWh.

$(Pe)_{ST}$ = Electric energy output plus mechanical energy output (if any) of steam turbines in MWh.

$(Pe)_{CT}$ = Electric energy output plus mechanical energy output (if any) of stationary combustion turbine(s) in MWh.

$(Pe)_{IE}$ = Electric energy output plus mechanical energy output (if any) of your affected facility's integrated equipment that provides electricity or mechanical energy to the affected facility or auxiliary equipment in MWh.

$(Pe)_{FW}$ = Electric energy used to power boiler feedwater pumps at steam generating units in MWh. Not applicable to stationary combustion turbines or IGCC facilities.

$(Pt)_{PS}$ = Useful thermal energy output of steam measured relative to ISO conditions that is used for applications that do not generate additional electricity, produce mechanical energy output, or enhance the performance of the affected facility. Calculated using the equation specified in paragraph (g)(3)(iii)(B) of this section in MWh.

$(Pt)_{HR}$ = Hourly useful thermal energy output measured relative to ISO conditions from heat recovery that is used for applications other than steam generation or performance enhancement of the affected facility in MWh.

$(Pt)_{IE}$ = Useful thermal energy output relative to ISO conditions from any integrated equipment that provides thermal energy to the affected facility or auxiliary equipment in MWh.

T = Electric Transmission and Distribution Factor.

T = 0.95 for a combined heat and power affected facility where at least on an annual basis 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 energy output on a rolling 3 year basis.

T = 1.0 for all other affected facilities.

(ii) If applicable to your affected facility, you must calculate $(Pt)_{PS}$ using the following equation:

$$(Pt)_{PS} = \frac{Q_m \times H}{3.6 \times 10^9}$$

Where:

Q_m = Measured steam flow in kilograms (kg) (or pounds (lb)) for the operating hour.

H = Enthalpy of the steam at measured temperature and pressure relative to ISO conditions in Joules per kilogram (J/kg) (or Btu/lb).

3.6×10^9 = Conversion factor (J/MWh) (or 3.413×10^6 Btu/MWh).

(4) You must calculate the total gross output for the affected facility's compliance period by summing the hourly gross output values for the affected facility that you determined from paragraph (a)(2) of this section for all of the operating hours in the applicable compliance period.

(5) You must calculate the CO_2 mass emissions rate for the affected facility by dividing the total CO_2 mass emissions value calculated according to the procedures in paragraph (a)(2) of this section by the total gross output value calculated according to the procedures in paragraph (a)(4) of this section.

(b) If the CO_2 mass emissions rate for your affected facility that you determined according to the procedures specified in paragraph (a) of this section is less than or equal to the CO_2 emissions standard in Table 1 of this subpart applicable to the affected facility, then your affected facility is in compliance with the emissions standard. If the average CO_2 mass emissions rate is greater than the CO_2 emissions standard in Table 1 of this subpart applicable to the affected facility, then your affected facility has excess CO_2 emissions.

Notification, Reports, and Records

§ 60.5550 What notifications must I submit and when?

(a) You must prepare and submit the notifications specified in §§ 60.7(a)(1) and (a)(3) and 60.19, as applicable to your affected facility.

(b) You must prepare and submit notifications specified in § 75.61 of this chapter, as applicable to your affected facility.

§ 60.5555 What reports must I submit and when?

(a) You must prepare and submit reports according to paragraphs (a) through (d) of this section, as applicable.

(1) For affected facilities that are required by § 60.5525 to conduct initial and on-going compliance determinations on a 12- or 84-operating month rolling average basis for the standard in § 60.5520 you must submit electronic quarterly reports as follows. After you have accumulated the first 12-operating months for the affected facility (or, the first 84-operating months for an affected facility electing to comply with the 84-operating month standard), you must submit a report for the calendar quarter that includes the twelfth (or eighty-fourth) operating month no later than 30 days after the end of that quarter. Thereafter, you must submit a report for each subsequent calendar quarter, no later than 30 days after the end of the quarter.

(2) In each quarterly report you must include the following information, as applicable:

(i) Each rolling average CO_2 mass emissions rate for which the last (12th or eighty-fourth) operating month in a 12- or 84-operating month compliance period falls within the calendar quarter. You must calculate each average CO_2 mass emissions rate according to the procedures in § 60.5540. You must report the dates (month and year) of the first and twelfth (or eighty-fourth) operating months in each compliance period for which you performed a CO_2 mass emissions rate calculation. If there are no compliance periods that end in the quarter, you must include a statement to that effect;

(ii) If one or more compliance periods end in the quarter you must identify each operating month in the calendar quarter with excess CO_2 emissions;

(iii) The percentage of valid CO_2 mass emission rates (as defined in § 60.5540) in each 12- or 84-operating month compliance period described in paragraph (a)(1)(i) of this section (i.e., the total number of valid CO_2 mass emission rates in that period divided by the total number of operating hours in that period, multiplied by 100 percent); and

(iv) The CO_2 emissions standard (as identified in Table 1 of this subpart) with which your affected facility is complying.

(3) In the final quarterly report of each calendar year, you must include the following:

(i) Gross electric output sold to an electric grid over the 4 quarters of the calendar year; and

(ii) The potential electric output of the facility.

(b) You must submit all electronic reports required under paragraph (a) of this section using the Emissions Collection and Monitoring Plan System (ECMPS) Client Tool provided by the Clean Air Markets Division in the Office of Atmospheric Programs of EPA.

(c) You must meet all applicable reporting requirements and submit reports as required under subpart G of part 75 of this chapter.

(d) If your affected unit employs geologic sequestration to meet the applicable emission limit, you must report in accordance with the requirements of 40 CFR part 98, subpart PP and either:

(1) if injection occurs onsite, report in accordance with the requirements of 40 CFR part 98, subpart RR, or

(2) if injection occurs offsite, transfer the captured CO_2 to a facility or facilities that reports in accordance with the requirements of 40 CFR part 98, subpart RR.

§ 60.5560 What records must I maintain?

(a) You must maintain records of the information you used to demonstrate compliance with this subpart as specified in § 60.7(b) and (f).

(b) You must follow the applicable recordkeeping requirements and maintain records as required under subpart F of part 75 of this chapter.

(c) You must keep records of the calculations you performed to determine the total CO_2 mass emissions for:

(1) Each operating month (for all affected units);

(2) Each compliance period, including, as applicable, each 12-operating month compliance period and the 84-operating month compliance period.

(d) You must keep records of the applicable data recorded and calculations performed that you used to determine your affected facility's gross output for each operating month.

(e) You must keep records of the calculations you performed to determine the percentage of valid CO_2 mass emission rates in each compliance period.

(f) You must keep records of the calculations you performed to assess compliance with each applicable CO_2 mass emissions standard in § 60.5520.

(g) You must keep records of the calculations you performed to determine any site-specific carbon-based F-factors you used in the emissions calculations (if applicable).

§ 60.5565 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review.

(b) You must maintain each record for 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record except those records required to demonstrate

compliance with an 84-operating month compliance period. You must maintain records required to demonstrate compliance with an 84-operating month compliance period for at least 10 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You 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. You may maintain the records off site and electronically for the remaining year(s) as required by this subpart.

Other Requirements and Information

§ 60.5570 What parts of the General Provisions apply to my affected facility?

Notwithstanding any other provision of this chapter, certain parts of the General Provisions in §§ 60.1 through 60.19, listed in Table 2 of this subpart, do not apply to your affected facility.

§ 60.5575 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or a delegated authority such as your state, local, or tribal agency. If the Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency, the Administrator retains the authorities listed in paragraphs (b)(1) through (5) of this section and does not transfer them to the state, local, or tribal agency. In addition, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the emission standards.

(2) Approval of major alternatives to test methods.

(3) Approval of major alternatives to monitoring.

(4) Approval of major alternatives to recordkeeping and reporting.

(5) Performance test and data reduction waivers under § 60.8(b).

§ 60.5580 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 subpart A (General Provisions of this part).

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

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, *baseload* 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).

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.

Coal refuse means waste products of coal mining, physical coal cleaning, and coal preparation operations (*e.g.* culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

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 energy from the same primary energy source.

Distillate oil means fuel oils that contain no more than 0.05 weight percent nitrogen and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 60.17); diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 60.17); kerosene, as defined by the American Society of Testing and Materials in ASTM D3699 (incorporated by reference, see § 60.17); biodiesel as defined by the American Society of Testing and Materials in ASTM D6751 (incorporated by reference, see § 60.17); or biodiesel blends as defined by the American Society of Testing and Materials in ASTM D7467 (incorporated by reference, see § 60.17).

Excess emissions means a specified averaging period over which the CO_2 emissions rate is higher than the applicable emissions standard located in Table 1 of this subpart.

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.

Gross energy output means:

(1) For stationary combustion turbines and IGCC facilities, the gross electric or direct mechanical output from both the unit (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) plus 75 percent of the useful thermal output measured relative to ISO 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 electric utility steam generating units, the gross electric or mechanical output from the affected facility (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps plus 75 percent of the useful thermal output measured relative to ISO 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);

(3) 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 thermal output on a rolling 3 year basis, the gross electric or mechanical output from the affected facility (including, but not limited to, output from steam turbine(s), combustion turbine(s), and gas expander(s)) minus any electricity used to power the feedwater pumps (the electric auxiliary load of boiler feedwater pumps is not applicable to

IGCC facilities), that difference divided by 0.95, plus 75 percent of the useful thermal output measured relative to ISO 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).

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 stationary combustion turbine that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas. 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 energy, 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:

(1) The gross electric sales to the utility power distribution system minus purchased power on a three calendar year rolling average basis; or

(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 at least 20.0 percent of the total gross energy output consists of useful thermal output on a 3 calendar year rolling average basis, the gross electric sales to the utility power distribution system minus purchased power of the thermal host facility or facilities on a three calendar year rolling average basis.

Oil means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate and residual oil, and gases derived from solid oil-derived fuels (not meeting the definition of natural gas).

Operating month means a calendar month during which any fuel is combusted in the affected facility at any time.

Potential electric output means 33 percent or the design electric output efficiency on a net output basis multiplied by the maximum design heat input capacity (expressed in MMBtu/h) of the steam generating unit, multiplied by 10^6 Btu/MMBtu, 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 affected facility with a 100 MW (341 MMBtu/h) fossil-fuel heat input capacity would have a 310,000 MWh 12 month potential electric output capacity).

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.

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 emission 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 enhance the performance of the affected facility. Thermal output for this subpart means the energy in recovered thermal output measured against the energy in the thermal output at ISO conditions.

TABLE 1 TO SUBPART TTTT OF PART 60—CO_2 EMISSION STANDARDS

[NOTE: all numerical values have a minimum of 2 significant figures]

Affected facility	CO_2 Emission standard
Stationary combustion turbine that has a base load rating heat input to the turbine engine of greater than 250 MW (850MMBtu/h).	450 kilograms (kg) of CO_2 per megawatt-hour (MWh) of gross output (1,000 lb/MWh) on a 12-operating month rolling average.
Stationary combustion turbine that has a design heat input to the turbine engine greater than 73 MW (250 MMBtu/h) and equal to or less than 250 MW (850MMBtu/h).	500 kg of CO_2 per MWh of gross output (1,100 lb CO_2/MWh) on a 12-operating month rolling average.

TABLE 1 TO SUBPART TTTT OF PART 60—CO_2 EMISSION STANDARDS—Continued

[NOTE: all numerical values have a minimum of 2 significant figures]

Affected facility	CO_2 Emission standard
Steam generating unit	500 kg of CO_2 per MWh of gross energy output (1,100 lb CO_2/MWh) on a 12-operating month rolling average basis; or 480 kg of CO_2 per MWh of gross energy output (1,050 lb CO_2/MWh) on an 84-operating month rolling average basis.
Integrated gasification combined cycle (IGCC) facility	500 kg of CO_2 per MWh of gross energy output (1,100 lb CO_2/MWh) on a 12-operating month rolling average basis; or 480 kg of CO_2 per MWh of gross energy output (1,050 lb CO_2/MWh) on an 84-operating month rolling average basis.

TABLE 2 TO SUBPART TTTT OF PART 60—APPLICABILITY OF SUBPART A GENERAL PROVISIONS TO SUBPART TTTT

General provisions citation	Subject of citation	Applies to subpart TTTT	Explanation
§ 60.1	Applicability	Yes.	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5580.
§ 60.3	Units and Abbreviations	Yes.	
§ 60.4	Address	Yes.	
§ 60.5	Determination of construction or modification	Yes.	
§ 60.6	Review of plans	Yes.	
§ 60.7	Notification and Recordkeeping	Yes	Only the requirements to submit the notification in § 60.7(a)(1) and (a)(3).
§ 60.8	Performance tests	No.	
§ 60.9	Availability of Information	Yes.	
§ 60.10	State authority	Yes.	
§ 60.11	Compliance with standards and maintenance requirements	No.	
§ 60.12	Circumvention	Yes.	
§ 60.13	Monitoring requirements	Yes.	
§ 60.14	Modification	No.	
§ 60.15	Reconstruction	No.	
§ 60.16	Priority list	No.	
§ 60.17	Incorporations by reference	Yes.	
§ 60.18	General control device requirements	No.	
§ 60.19	General notification and reporting requirements	Yes.	

PART 70—STATE OPERATING PERMIT PROGRAMS

■ 17. The authority citation for part 70 continues to read as follows:

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

■ 18. Section 70.2 is amended:

■ a. By adding in alphabetical order the definition of ''Greenhouse gases,''

■ b. By revising the introductory text, removing ''or'' from the end of paragraph (2), adding ''or'' to the end of paragraph (3), and adding paragraph (4) to the definition of ''Regulated pollutant (for presumptive fee calculation),'' and

■ c. By revising paragraph (1) to the definition of ''Subject to regulation.''

The revision and additions read as follows:

§ 70.2 Definitions.

* * * * *

Greenhouse gases (GHGs) means the air pollutant defined in § 86.1818–12(a) of this chapter as the aggregate group of six greenhouse gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

* * * * *

Regulated pollutant (for presumptive fee calculation), which is used only for purposes of § 70.9(b)(2), means any regulated air pollutant except the following:

* * * * *

(4) Greenhouse gases.

* * * * *

Subject to regulation * * *

(1) Greenhouse gases shall not be subject to regulation unless, as of July 1, 2011, the GHG emissions are at a stationary source emitting or having the potential to emit 100,000 tpy CO_2 equivalent emissions.

* * * * *

■ 19. Section 70.9 is amended by revising paragraph (b)(2)(i), and by adding paragraph (b)(2)(v) to read as follows:

§ 70.9 Fee determination and certification.

* * * * *

(b) * * *

(2)(i) The Administrator will presume that the fee schedule meets the requirements of paragraph (b)(1) of this section if it would result in the collection and retention of an amount not less than $25 per year [as adjusted pursuant to the criteria set forth in paragraph (b)(2)(iv) of this section] times the total tons of the actual emissions of each regulated pollutant (for presumptive fee calculation) emitted from part 70 sources and any GHG cost adjustment required under paragraph (b)(2)(v) of this section.

* * * * *

(v) *GHG cost adjustment.* The amount calculated in paragraph (b)(2)(i) of this section shall be increased by the GHG cost adjustment determined as follows:

For each activity identified in the following table, multiply the number of activities performed by the permitting authority by the burden hours per activity, and then calculate a total number of burden hours for all activities. Next, multiply the burden hours by the average cost of staff time, including wages, employee benefits and overhead.

Activity	Burden hours per activity
GHG completeness determination (for initial permit or updated application)	43
GHG evaluation for a modification or related permit action	7
GHG evaluation at permit renewal	10

* * * * *

PART 71—FEDERAL OPERATING PERMIT PROGRAMS

■ 20. The authority citation for part 71 continues to read as follows:

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

■ 21. Section 71.2 is amended:

■ a. By adding in alphabetical order the definition of ''Greenhouse gases,''

■ b. By removing ''or'' from the end of paragraph (2), adding ''or'' to the end of paragraph (3), and adding paragraph (4) to the definition of ''Regulated pollutant (for fee calculation),'' and

■ c. By revising paragraph (1) of the definition of ''Subject to regulation.''

The revisions and additions read as follows:

§ 71.2 Definitions.

* * * * *

Greenhouse gases (GHGs) means the air pollutant defined in § 86.1818–12(a) of this chapter as the aggregate group of six greenhouse gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

* * * * *

Regulated pollutant (for fee calculation), which is used only for purposes of § 71.9(c), means any ''regulated air pollutant'' except the following:

* * * * *

(4) Greenhouse gases.

* * * * *

Subject to regulation * * *

(1) Greenhouse gases shall not be subject to regulation unless, as of July 1, 2011, the GHG emissions are at a stationary source emitting or having the potential to emit 100,000 tpy CO_2 equivalent emissions.

* * * * *

■ 22. Section 71.9 is amended by:

■ a. Revising paragraphs (c)(1), (c)(2)(i), (c)(3), and (c)(4), and

■ b. Adding paragraph (c)(8).

The revisions and additions read as follows:

§ 71.9 Permit fees.

* * * * *

(c) * * *

(1) For part 71 programs that are administered by EPA, each part 71 source shall pay an annual fee which is the sum of:

(i) $32 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(ii) Any GHG fee adjustment required under paragraph (c)(8) of this section.

(2) * * *

(i) Where the EPA has not suspended its part 71 fee collection pursuant to paragraph (c)(2)(ii) of this section, the annual fee for each part 71 source shall be the sum of:

(A) $24 per ton (as adjusted pursuant to the criteria set forth in paragraph (n)(1) of this section) times the total tons of the actual emissions of each regulated pollutant (for fee calculation) emitted from the source, including fugitive emissions; and

(B) Any GHG fee adjustment required under paragraph (c)(8) of this section.

* * * * *

(3) For part 71 programs that are administered by EPA with contractor assistance, the per ton fee shall vary depending on the extent of contractor involvement and the cost to EPA of contractor assistance. The EPA shall establish a per ton fee that is based on the contractor costs for the specific part 71 program that is being administered, using the following formula: Cost per ton = $(E \times 32) + [(1 - E) \times \$\ C]$

Where E represents EPA's proportion of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, $1 - E$ represents the contractor's effort, and C represents the contractor assistance cost on a per ton basis. C shall be computed by using the following formula: $C = [\ B + T + N]$ divided by 12,300,000

Where B represents the base cost (contractor costs), where T represents travel costs, and where N represents nonpersonnel data management and tracking costs. In addition, each part 71 source shall pay a GHG fee adjustment for each activity as required under paragraph (c)(8) of this section.

(4) For programs that are delegated in part, the fee shall be computed using the following formula: Cost per ton = $(E \times 32) + (D \times 24) + [(1 - E - D) \times \$\ C]$

Where E and D represent, respectively, the EPA and delegate agency proportions of total effort (expressed as a percentage of total effort) needed to administer the part 71 program, $1 - E - D$ represents the contractor's effort, and C represents the contractor assistance cost on a per ton basis. C shall be computed using the formula for contractor assistance cost found in paragraph (c)(3) of this section and shall be zero if contractor assistance is not utilized. In addition, each part 71 source shall pay a GHG fee adjustment for each activity as required under paragraph (c)(8) of this section.

* * * * *

(8) *GHG fee adjustment.* The annual fee shall be increased by a GHG fee adjustment for any source that has initiated an activity listed in the following table since the fee was last paid. The GHG fee adjustment shall be equal to the set fee provided in the table for each activity that has been initiated since the fee was last paid:

Activity	Set fee
GHG completeness determination (for initial permit or updated application)	$2,236
GHG evaluation for a permit modification or related permit action	364
GHG evaluation at permit renewal	520

* * * * *

PART 98—MANDATORY GREENHOUSE GAS REPORTING

■ 23. The authority citation for part 98 is revised to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart PP—Suppliers of Carbon Dioxide

■ 24. Section 98.426 is amended by adding paragraph (h) to read as follows:

§ 98.426 Data reporting requirements.

* * * * *

(h) If you capture a CO_2 stream from an electricity generating unit that is subject to subpart D of this part and transfer CO_2 to any facilities that are subject to subpart RR of this part, you must:

(1) Report the facility identification number associated with the annual GHG report for the facility that is subject to subpart D of this part,

(2) Report each facility identification number associated with the annual GHG

reports for each facility that is subject to subpart RR of this part to which CO_2 is transferred, and

(3) Report the annual quantity of CO_2 in metric tons that is transferred to each facility that is subject to subpart RR of this part.

■ 25. Section 98.427 is amended by adding paragraph (d) to read as follows:

§ 98.427 Records that must be retained.

* * * * *

(d) Facilities subject to § 98.426(h) must retain records of CO_2 in metric tons that is transferred to each facility that is subject to subpart RR of this part.

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Part III

Securities and Exchange Commission

17 CFR Parts 240 and 249

Removal of Certain References to Credit Ratings Under the Securities Exchange Act of 1934; Final Rule

SECURITIES AND EXCHANGE COMMISSION

17 CFR Parts 240 and 249

[Release No. 34–71194; File No. S7–15–11]

RIN 3235–AL14

Removal of Certain References to Credit Ratings Under the Securities Exchange Act of 1934

AGENCY: Securities and Exchange Commission.

ACTION: Final rule.

SUMMARY: The Securities and Exchange Commission (the ''Commission'') is adopting amendments that remove references to credit ratings in certain rules and one form under the Securities Exchange Act of 1934 (the ''Exchange Act'') relating to broker-dealer financial responsibility and confirmations of securities transactions. This action implements a provision of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the ''Dodd-Frank Act'').

DATES: The amendments will become effective on July 7, 2014.

FOR FURTHER INFORMATION CONTACT: Michael A. Macchiaroli, Associate Director, at (202) 551–5525; Thomas K. McGowan, Deputy Associate Director, at (202) 551–5521; Randall W. Roy, Assistant Director, at (202) 551–5522; Mark M. Attar, Branch Chief, at (202) 551–5889; Carrie A. O'Brien, Special Counsel, at (202) 551–5640; and Rachel B. Yura, Attorney, at (202) 551–5729, Office of Financial Responsibility (Net Capital, Customer Protection, and Books and Records Requirements); and Joseph M. Furey, Assistant Chief Counsel; and Brice D. Prince, Special Counsel, Office of the Chief Counsel, at (202) 551–5550 (Confirmations of Securities Transactions); Division of Trading and Markets, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–7010.

SUPPLEMENTARY INFORMATION: The Commission is adopting amendments to Rules 10b–10,[1] 15c3–1,[2] 15c3–1a,[3] 15c3–1e,[4] 15c3–1f,[5] 15c3–3,[6] and 17a–4[7] under the Exchange Act and corresponding amendments to the General Instructions to Form X–17A–5, Part IIB.[8]

[1] 17 CFR 240.10b–10.

[2] 17 CFR 240.15c3–1.

[3] 17 CFR 240.15c3–1a.

[4] 17 CFR 240.15c3–1e.

[5] 17 CFR 240.15c3–1f.

[6] 17 CFR 240.15c3–3.

[7] 17 CFR 240.17a–4.

[8] *See* the General Instructions to Form X–17A–5, Part IIB (referenced in 17 CFR 249.617).

I. Introduction

On July 21, 2010, the President signed the Dodd-Frank Act into law.[9] This legislation was enacted to, among other things, promote the financial stability of the United States by improving accountability and transparency in the financial system.[10] Section 939A of the Dodd-Frank Act requires each Federal agency, including the Commission, to review any regulation issued by such agency that requires the use of an assessment of the creditworthiness of a security or money market instrument and any references to or requirements in such regulations regarding credit ratings.[11] The section further provides that each such agency shall ''modify any such regulations identified by the review . . . to remove any reference to or requirement of reliance on credit ratings, and to substitute in such regulations such standard of creditworthiness as each respective agency shall determine as appropriate for such regulations.'' [12]

II. Discussion

A. Background

Prior to and after enactment of the Dodd-Frank Act, the Commission has taken a number of steps toward removing references to credit ratings from its regulations under the federal securities laws.[13] These steps include a 2011 proposal to remove references to credit ratings of nationally recognized statistical rating organizations (''NRSROs'') from certain rules under the Exchange Act relating to broker-dealer financial responsibility (Rule 15c3–1, Rule 15c3–3, and Form X–17A–5, Part IIB), confirmations of securities transactions (Rule 10b–10), and distributions of securities (Rules 101 and 102 of Regulation M).[14] Today the Commission is adopting amendments to remove references to credit ratings in the broker-dealer financial responsibility and confirmations of transactions rules. In doing so, the Commission considered its prior actions in this area. Regarding its proposal to remove credit ratings from its rules under Regulation M applicable to distributions of securities, the Commission is currently reviewing comments and considering alternatives and intends to address this proposal separately.[15] In taking these actions, the Commission has carefully considered the eleven comment letters it received in response to the proposing release,[16]

[9] *See* Public Law 111–203, 124 Stat. 1376 (2010).

[10] *Id.* at Preamble.

[11] Public Law 111–203 § 939A(a)(1)–(2). In July 2011, the Commission published a report on the staff's review of Commission regulations that relied on credit ratings. *See* Commission Staff, *Report on Review of Reliance on Credit Ratings: As Required by Section 939A(c) of the Dodd-Frank Wall Street Reform and Consumer Protection Act* (July 2011). Section 939A of the Dodd-Frank Act applies to all federal agencies.

[12] *See* Public Law 111–203 § 939A(b).

[13] *See, e.g., Nationally Recognized Statistical Rating Organizations,* Exchange Act Release No. 34616 (Aug. 31, 1994), 59 FR 46314 (Sep. 7, 1994) (soliciting comment on, among other things, whether references to NRSRO credit ratings should be eliminated from Commission rules); *Rating Agencies and the Use of Credit Ratings under the Federal Securities Laws,* Exchange Act Release No. 47972 (June 4, 2003), 68 FR 35258 (June 12, 2003) (soliciting comment on whether to eliminate the use of NRSRO credit ratings, and, if so, what alternative benchmarks could be used to meet the Commission's regulatory objectives); *References to Ratings of Nationally Recognized Statistical Rating Organizations,* Exchange Act Release No. 58070 (July 1, 2008), 73 FR 40088 (July 11, 2008) (proposing amendments to remove references to credit ratings from Commission rules under the Securities Act of 1933 (''Securities Act''), Exchange Act, and Investment Company Act of 1940 (''Investment Company Act'')); *References to Ratings of Nationally Recognized Statistical Rating Organizations,* Exchange Act Release No. 60789 (Oct. 5, 2009), 74 FR 52358 (Oct. 9, 2009) (adopting amendments to remove references to credit ratings in certain Commission rules); *References to Ratings of Nationally Recognized Statistical Rating Organizations,* Exchange Act Release No. 60790 (Oct. 5, 2009), 74 FR 52374 (Oct. 9, 2009) (re-opening comment on proposals to remove references to credit ratings in certain Commission rules); *Security Ratings,* Securities Act Release No. 9186 (Feb. 9, 2011), 76 FR 8961 (Feb. 16, 2011) (proposing amendments to remove references to credit ratings in certain Commission rules); *References to Credit Ratings in Certain Investment Company Act Rules and Forms,* Securities Act Release No. 9193 (Mar. 3, 2011), 76 FR 12896 (Mar. 9, 2011) (proposing amendments to remove references to credit ratings in certain Commission rules); *Security Ratings,* Securities Act Release No. 9245 (July 27, 2011), 76 FR 46603 (Aug. 3, 2011) (adopting amendments to remove references to credit ratings in certain Commission rules).

[14] *See Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* Exchange Act Release No. 64352 (Apr. 27, 2011), 76 FR 26550 (May 6, 2011). The Commission also proposed amendments in 2011 to remove references to credit ratings in rules under the Securities Act and the Investment Company Act. *See References to Credit Ratings in Certain Investment Company Act Rules and Forms,* 76 FR 12896; *Security Ratings,* 76 FR 8961.

[15] Regulation M is a set of anti-manipulation rules designed to preserve the integrity of the securities market by prohibiting activities that could artificially influence the market for an offered security. *See* 17 CFR 242.100–105. The rules include an exception for nonconvertible debt securities, nonconvertible preferred securities, and asset-backed securities that are rated by at least one NRSRO in one of its generic rating categories that signifies investment grade. *See* 17 CFR 242.101(c)(2); 17 CFR 242.102(d)(2).

[16] Comment letter of Chris Barnard (June 6, 2011) (''*Barnard Letter*''); comment letter of Creative Investment Research, Inc. (July 4, 2011) (''*Creative Investment Letter*''); comment letter of Rothwell Consulting LLC (July 5, 2011) (''*Rothwell Consulting Letter*''); comment letter of Davis Polk & Wardwell LLP (July 5, 2011) (''*Davis Polk Letter*''); comment letter of Bond Dealers of America (July 5, 2011) (''*Bond Dealers Letter*''); comment letter of the Securities Industry and Financial Markets Association (July 5, 2011) (''*SIFMA Letter*'');

five of which discussed the proposed amendments to the broker-dealer financial responsibility rules,[17] and four of which discussed the proposed amendments to the confirmations of transactions rule.[18]

A number of other federal agencies have also taken action to implement section 939A of the Dodd-Frank Act, including regulations proposed or adopted by the Commodity Futures Trading Commission,[19] the Office of the Comptroller of the Currency,[20] the National Credit Union Administration,[21] the Federal Housing Finance Agency,[22] the Department of Labor,[23] and jointly by the Office of the Comptroller of the Currency and the Federal Reserve Board.[24] The actions taken by these other regulators were considered in adopting today's amendments.

The following discussion summarizes the Commission's proposals with respect to the broker-dealer financial responsibility and confirmations of transaction rules, the comments received by the Commission in response to each of the proposals, and the amendments the Commission is adopting today.[25]

B. Amendments

1. The Broker-Dealer Financial Responsibility Rules

a. The Net Capital Rule

i. Proposal

In 1975, the Commission adopted the term *nationally recognized statistical rating organization* as part of amendments to the broker-dealer net capital rule (''Rule 15c3–1'').[26] The Commission's initial regulatory use of the term was intended to provide a method for determining net capital charges on different grades of debt securities under Rule 15c3–1.[27] Rule 15c3–1 prescribes a net liquid assets test that is designed to require a broker-dealer to maintain sufficient liquid assets to meet all obligations to customers and counterparties and have adequate additional resources to wind-down its business in an orderly manner without the need for a formal proceeding if the firm fails financially.[28] Among other things, Rule 15c3–1 requires broker-dealers to maintain specified minimum levels of net liquid assets, or net capital.[29] In particular, it requires that a broker-dealer perform two calculations: (1) a computation of the minimum amount of net capital the broker-dealer must maintain;[30] and (2) a computation of the amount of net capital the broker-dealer is maintaining.[31] The minimum net capital requirement is the greater of a fixed-dollar amount specified in the rule or an amount determined by applying one of two financial ratios.[32]

In computing net capital, a broker-dealer must, among other things, make certain adjustments to net worth, including deducting illiquid assets, taking other net capital charges, and adding qualifying subordinated loans.[33] The amount remaining after these adjustments is defined as *tentative net capital*.[34] The final step in computing net capital is to take prescribed percentage deductions (''haircuts'') from the mark-to-market value of proprietary positions (*e.g.,* securities, money market instruments, and commodities) that are included in the broker-dealer's tentative net capital.[35] The haircuts are designed to account for the market risk inherent in these positions and create a buffer of liquidity to protect against other risks associated with the securities business.[36]

Rule 15c3–1 prescribes differing haircut amounts for a variety of classes of securities.[37] The rule also contains catchall provisions to account for securities that are not included in the specified classes of securities.[38] Generally, the catchall provisions impose higher deductions (15% or 40% of the mark-to-market value of the positions) than the haircuts applicable to the specifically identified classes of securities.[39] Further, if a security does not have a ready market, it is subject to a 100% deduction from net worth.[40]

comment letter of Better Markets, Inc. (July 5, 2011) (''*Better Markets Letter*''); comment letter of Sullivan & Cromwell LLP (July 5, 2011) (''*Sullivan & Cromwell Letter*''); comment letter of the Securitization Group, Securities Industry and Financial Markets Association (Sep. 23, 2011) (''*SIFMA Securitization Letter*''); comment letter of the CFA Institute (Dec. 20, 2011) (''*CFA Institute Letter*''); and comment letter of the Honorable Sean P. Duffy, U.S. House of Representatives (Oct. 4, 2013) (''*Duffy Letter*''). These comment letters are *available at http://www.sec.gov/comments/s7-15-11/s71511.shtml.* Comments are also available for Web site viewing and printing in the Commission's Public Reference Room, 100 F Street NE., Washington, DC (File No. S7–15–11).

[17] *See Barnard Letter; Better Markets Letter; Bond Dealers Letter; CFA Institute Letter; SIFMA Letter.*

[18] *See Better Markets Letter; CFA Institute Letter; SIFMA Letter; Sullivan & Cromwell Letter.* In addition, one letter discussed the proposed amendments to Regulation M and one letter discussed reference removal under section 939A generally. *See Rothwell Consulting Letter* (Regulation M); *Duffy Letter* (section 939A generally).

[19] *See Investment of Customer Funds and Funds Held in an Account for Foreign Futures and Foreign Options Transactions,* 76 FR 78776 (Dec. 19, 2011) (final rule); *Removing Any Reference to or Reliance on Credit Ratings in Commission Regulations; Proposing Alternatives to the Use of Credit Ratings,* 76 FR 44262 (July 25, 2011) (final rule).

[20] *See Alternatives to the Use of External Credit Ratings in the Regulations of the OCC,* 77 FR 35253 (June 13, 2012) (final rule).

[21] *See Alternatives to the Use of Credit Ratings,* 77 FR 74103 (Dec. 13, 2012) (final rule).

[22] *See Removal of References to Credit Ratings in Certain Regulations Governing the Federal Home Loan Banks,* 78 FR 30784 (May 23, 2013) (proposed rule).

[23] *See Proposed Amendments to Class Prohibited Transaction Exemptions to Remove Credit Ratings Pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act,* 78 FR 37572 (June 21, 2013) (proposed rule).

[24] *See Regulatory Capital Rules: Regulatory Capital, Implementation of Basel III, Capital Adequacy, Transition Provisions, Prompt Corrective Action, Standardized Approach for Risk-Weighted Assets, Market Discipline and Disclosure Requirements, Advanced Approaches Risk-Based Capital Rule, and Market Risk Capital Rule,* 78 FR 62018 (Oct. 11, 2013) (interim final rule with request for comment).

[25] In a separate release, the Commission is adopting final amendments to remove references to credit ratings in Rule 5b–3 and Forms N–1A, N–2, and N–3 under the Investment Company Act.

[26] *See Adoption of Uniform Net Capital Rule and an Alternative Net Capital Requirement for Certain Brokers and Dealers,* Exchange Act Release No. 11497 (June 26, 1975), 40 FR 29795 (July 16, 1975); 17 CFR 240.15c3–1.

[27] *See* 17 CFR 240.15c3–1.

[28] *See Net Capital Rule,* Exchange Act Release No. 38248 (Feb. 6, 1997), 62 FR 6474 (Feb. 12, 1997).

[29] *See* 17 CFR 240.15c3–1.

[30] *See* 17 CFR 240.15c3–1(a).

[31] *See* 17 CFR 240.15c3–1(c)(2). The computation of net capital is based on the definition of *net capital* in paragraph (c)(2) of Rule 15c3–1. *Id.*

[32] *See* 17 CFR 240.15c3–1(a).

[33] *See* 17 CFR 240.15c3–1(c)(2)(i) through (xiii).

[34] *See* 17 CFR 240.15c3–1(c)(15).

[35] *See* 17 CFR 240.15c3–1(c)(2)(vi).

[36] *See, e.g., Uniform Net Capital Rule,* Exchange Act Release No. 13635 (June 16, 1977), 42 FR 31778 (June 23, 1977) (''[Haircuts] are intended to enable net capital computations to reflect the market risk inherent in the positioning of the particular types of securities enumerated in [the rule.]''); *Net Capital Rule,* Exchange Act Release No. 22532 (Oct. 15, 1985), 50 FR 42961 (Oct. 23, 1985) (''These percentage deductions, or 'haircuts', take into account elements of market and credit risk that the broker-dealer is exposed to when holding a particular position.''); *Net Capital Rule,* Exchange Act Release No. 39455 (Dec. 17, 1997), 62 FR 67996 (Dec. 30, 1997) (''Reducing the value of securities owned by broker-dealers for net capital purposes provides a capital cushion against adverse market movements and other risks faced by the firms, including liquidity and operational risks.'') (footnote omitted).

[37] *See* 17 CFR 240.15c3–1(c)(2)(vi)(A) through (H).

[38] *See* 17 CFR 240.15c3–1(c)(2)(vi)(J) through (K).

[39] *Compare* 17 CFR 240.15c3–1(c)(2)(vi)(A) through (H), *with* 17 CFR 240.15c3–1(c)(2)(vi)(J) through (K).

[40] *See* 17 CFR 240.15c3–1(c)(2)(vii). The term *ready market* is defined in Rule 15c3–1 as ''a market in which there exists independent bona fide offers to buy and sell so that a price reasonably related to the last sales price or current bona fide competitive bid and offer quotations can be determined for a particular security almost instantaneously and where payment will be received in settlement of a sale at such price within a relatively short time conforming to trade custom.'' 17 CFR 240.15c3–1(c)(11).

Prior to today's amendments, commercial paper, nonconvertible debt, and preferred stock rated in higher rating categories by at least two NRSROs were included in the classes of securities that had lower haircuts than securities subject to the catchall provisions.[41] Specifically, to qualify for this treatment, among other things, commercial paper needed to be rated in one of the three highest rating categories by at least two NRSROs,[42] nonconvertible debt needed to be rated in one of the four highest rating categories by at least two NRSROs,[43] and preferred stock needed to be rated in one of the four highest rating categories by at least two NRSROs.[44] Broker-dealers were not required to take as large a haircut for commercial paper, nonconvertible debt, and preferred stock meeting these rating conditions because the securities were considered to be less volatile in price than securities that were rated in lower rating categories or were unrated.

The Commission proposed to remove references to credit ratings in the provisions of Rule 15c3–1 establishing lower haircuts for higher rated commercial paper, nonconvertible debt, and preferred stock and to substitute an alternative standard of creditworthiness as a condition for qualifying for the lower haircut treatment.[45] The proposed amendments retained the non-credit rating conditions for these classes of securities to apply lower haircuts. Under the proposal, a broker-dealer would have been permitted to apply the lower haircuts for commercial paper (*i.e.,* between zero and ½ of 1%), nonconvertible debt (*i.e.,* between 2% and 9%), and preferred stock (*i.e.,* 10%) if the position had only a minimal amount of credit risk as determined by the broker-dealer pursuant to written policies and procedures the broker-dealer established, maintained, and enforced to assess creditworthiness.[46] Consequently, to use these lower haircuts for commercial paper, nonconvertible debt, and preferred stock, a broker-dealer would have been required to establish, maintain, and enforce written policies and procedures designed to assess the credit risks applicable to the position and, based on this process, would have had to determine that the investment had only a minimal amount of credit risk.[47] A broker-dealer would have been required to take a larger deduction, normally the 15% ''catchall'' haircut, on its proprietary positions in commercial paper, nonconvertible debt, and preferred stock if the firm did not have procedures to assess the creditworthiness of the class of security or money market instrument or determined its position was not of minimal credit risk.[48] Moreover, if an issuance of commercial paper, nonconvertible debt, or preferred stock did not trade in a ready market, the broker-dealer would continue to apply a 100% haircut—meaning that the broker-dealer could not include the value of the security in its net capital.[49]

In the proposing release, the Commission identified the following factors a broker-dealer could consider, to the extent appropriate, when assessing credit risk for purposes of determining whether an issuance of commercial paper, nonconvertible debt, or preferred stock was of minimal credit risk: (1) Credit spreads; (2) securities-related research; (3) internal or external credit risk assessments; (4) default statistics; (5) inclusion in an index; (6) priorities and enhancements; (7) price, yield and/or volume; and (8) asset class-specific factors.[50] The Commission stated that the list of factors was not intended to be exhaustive nor mutually exclusive and that the range and type of specific factors considered would vary depending on the particular securities that were reviewed.[51]

In addition, each broker-dealer would have been required to preserve for a period of not less than three years (the first two years in an easily accessible place) the written policies and procedures that the broker-dealer established, maintained, and enforced for assessing credit risk for commercial paper, nonconvertible debt, and preferred stock.[52] Broker-dealers would have been subject to this requirement in the broker-dealer record retention rule (Rule 17a–4), which the Commission proposed to amend in conjunction with the rulemaking.[53]

ii. Comments

Five commenters responded to the Commission's request for comment on the amendments to Rule 15c3–1.[54] One additional commenter—writing about section 939A generally—supported the goals of section 939A to provide incentive for more information and diligence for investors and to increase competition in the credit rating agency industry but also cautioned that implementation of section 939A could be confusing to smaller banks and investors.[55] Two commenters raised concerns generally about replacing credit ratings with a more subjective standard of creditworthiness.[56] Three other commenters suggested modifications to the Commission's list of factors that a broker-dealer could consider when assessing creditworthiness under the proposed minimal amount of credit risk standard.[57] Commenters also generally supported the Commission's proposal that broker-dealers document and retain their policies and procedures for assessing a position's creditworthiness to determine whether it is of minimal credit risk.[58]

Among commenters raising concerns about the Commission replacing credit ratings with a more subjective approach for determining haircuts, one commenter stated that the proposal contains an inherent conflict of interest, is complicated, and would disproportionately burden smaller

[41] *See* 17 CFR 240.15c3–1(c)(2)(vi)(E), (F), and (H). Generally, the haircut requirements in Rule 15c3–1 prior to today's amendments were based on the practice of many NRSROs having at least eight categories of ratings for debt securities, with the top four ratings commonly referred to in the industry as *investment grade.*

[42] *See* 17 CFR 240.15c3–1(c)(2)(vi)(E). The amount of the haircut ranged from 0% to ½ of 1% depending on the time to maturity of the commercial paper. *Id.* Additional conditions to qualify for this treatment were that the commercial paper had a maturity at date of issuance not exceeding nine months exclusive of days of grace, or any renewal thereof, the maturity of which was likewise limited, and a fixed rate of interest or been sold at a discount. *Id.*

[43] *See* 17 CFR 240.15c3–1(c)(2)(vi)(F). The amount of the haircut ranged from 2% to 9% depending on the time to maturity of the nonconvertible debt security. *Id.* Additional conditions to qualify for this treatment were that the nonconvertible debt security had a fixed rate of interest, a fixed maturity, and did not trade flat and was not in default as to principal or interest. *Id.*

[44] *See* 17 CFR 240.15c3–1(c)(2)(vi)(H). The amount of the haircut was 10%. *Id.* Additional conditions to qualify for this treatment were that the preferred stock ranked prior to all other classes of stock of the same issuer and was not in arrears as to dividends. *Id.*

[45] *See Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26552–26554.

[46] *Id.* at 26552.

[47] *Id.*

[48] *Id.*

[49] *Id.*

[50] *Id.* at 26552–26553.

[51] *Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26553.

[52] *Id.* at 26553.

[53] *Id.; see also* 17 CFR 240.17a–4.

[54] *See Barnard Letter; Better Markets Letter; Bond Dealers Letter; CFA Institute Letter; SIFMA Letter; see also Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26554.

[55] *See Duffy Letter,* at 1.

[56] *See Bond Dealers Letter,* at 2–3; *SIFMA Letter,* at 11.

[57] *See Barnard Letter,* at 1–2; *Better Markets Letter,* at 6–7; *CFA Institute Letter,* at 4.

[58] *See Barnard Letter,* at 2; *Better Markets Letter,* at 6–8.

firms.[59] This commenter also stated that the Commission's proposal could result in inconsistent net capital treatment across broker-dealers absent a mandatory list of factors or an objective standard that a broker-dealer could apply when determining net capital haircuts—''[f]or example, one firm may determine a security qualifies for a 9% haircut, while another might determine the haircut for the same security is 15%.'' [60] This commenter also has concerns that a subjective approach would reduce liquidity, increase volatility, and could increase costs for issuers of securities.[61]

The second commenter expressed concern that Commission and self-regulatory organization (''SRO'') examiners would ''second guess'' a broker-dealer's policies and procedures and analysis under the new standard and that examiners should, instead, focus on the reasonableness of the policies and procedures.[62] This commenter also requested that examiners avoid duplicating the work of other regulators who have already considered the adequacy of a broker-dealer's policies and procedures for assessing the creditworthiness of securities positions.[63]

Regarding the Commission's proposed list of factors that broker-dealers could consider when assessing creditworthiness under the minimal amount of credit risk standard, one commenter recommended that the Commission require broker-dealers to consider certain mandatory factors and suggested they be codified in the final rule.[64] In contrast, another commenter did not believe that factors should be codified in the rule.[65] Another stated that a broker-dealer's assessment of a security's creditworthiness should be based on ''hard'' factors, such as credit spreads and default statistics, rather than ''soft'' factors, such as securities-related research.[66]

One commenter requested that ''term to maturity'' and ''concentration of credit risk'' be included as factors that a broker-dealer could consider in assessing whether a position is of minimal credit risk.[67] Another suggested that a broker-dealer's policies and procedures for assessing creditworthiness under the proposed standard be permitted to take into account the ''size of the [broker-dealer's] position and the purpose for which the position [was] acquired or held by the broker-dealer.'' [68] This commenter also stated that a broker-dealer's obligation to monitor credit determinations should be based on factors such as the volatility of business conditions within the relevant industry and the frequency with which the securities trade.[69]

One commenter suggested that a broker-dealer be allowed to rely on a parent's or an affiliate's credit determination.[70] Another stated that, to promote regulatory and market transparency, a broker-dealer that develops internal credit ratings should be required to compare its ratings to an external benchmark, such as NRSRO ratings, market data, or other credit information sources.[71] Another stated, however, that a broker-dealer should be prohibited from considering internally or externally developed credit ratings as part of its credit risk assessment process and that permitting such use would conflict with section 939A of the Dodd-Frank Act.[72]

Commenters generally supported the Commission's proposal that broker-dealers document their policies and procedures for determining creditworthiness under the minimal amount of credit risk standard.[73] One commenter suggested that such documentation be maintained indefinitely.[74] Another stated that the Commission should require a broker-dealer to maintain a record for each assessment of creditworthiness under the standard.[75] Another stated that the Commission should only require the retention of records for determinations of credit risk when a broker-dealer is engaged in ''sophisticated credit analysis.'' [76] This commenter stated that a broker-dealer should not be required to document its credit analysis with respect to a position if the analysis was based on a small number of objective factors and could be easily reconstructed by the broker-dealer.[77]

iii. Final Rule

The Commission is amending Rule 15c3–1 to remove references to NRSRO credit ratings in the provisions establishing lower haircuts for commercial paper, nonconvertible debt, and preferred stock. The Commission is adopting amendments to these provisions with modifications from the proposal, discussed below, to address issues raised by commenters.

Under the final amendments and consistent with the proposal, when a broker-dealer applies haircuts for commercial paper, nonconvertible debt, and preferred stock that have a ready market for purposes of its net capital computation, it will have the option of: (1) Using the firm's own written policies and procedures to determine whether the security has only a minimal amount credit risk and, if so, applying the appropriate lower haircut if it meets the other conditions prescribed in Rule 15c3–1; or (2) applying the greater deduction applicable to the position, such as the 15% haircut under the catchall provision in paragraph (c)(2)(vi)(J) of Rule 15c3–1.[78] Commercial paper, nonconvertible debt, and preferred stock without a ready market would continue to be subject to a 100% haircut.[79]

Unlike the objective approach of using NRSRO credit ratings, the minimal amount of credit risk standard is a subjective approach because it allows broker-dealers in the first instance to determine through their credit assessments whether a lower haircut is applicable to a given position. Further, whereas the rule prior to today's amendments required that commercial paper, nonconvertible debt, and preferred stock be given high credit ratings by an NRSRO before a reduced haircut is permitted, the minimal amount of credit risk standard provides flexibility to broker-dealers by allowing them to rely on a variety of factors, both objective and subjective, in assessing the credit and liquidity risks associated with their proprietary commercial paper, nonconvertible debt, and preferred stock positions. However, the Commission does not intend for the new standard to result in a more liberal requirement that broadens the scope of

[59] *Bond Dealers Letter,* at 2. This commenter argued that the proposed amendments disadvantage smaller broker-dealers that lack the necessary internal resources to determine creditworthiness and, as a result, will be unable to apply reduced haircuts.

[60] *Id.*

[61] *Id.*

[62] *SIFMA Letter,* at 19.

[63] *Id.* at 20–21.

[64] *Better Markets Letter,* at 5–6.

[65] *SIFMA Letter,* at 20.

[66] *Barnard Letter,* at 2.

[67] *CFA Institute Letter,* at 4.

[68] *SIFMA Letter,* at 10–11.

[69] *Id.* at 21.

[70] *Id.*

[71] *CFA Institute Letter,* at 4.

[72] *Better Markets Letter,* at 7.

[73] One commenter stated that broker-dealers would otherwise make self-interested determinations at the expense of customers. *Better Markets Letter,* at 6–8. Another commenter stated that these policies and procedures should be preserved for three years and updated to reflect significant changes. *Barnard Letter,* at 2. This commenter further argued that broker-dealers that create and enforce procedures to determine creditworthiness be granted the lesser haircut. *Id.*

[74] *Barnard Letter,* at 2.

[75] *Better Markets Letter,* at 7–8.

[76] *SIFMA Letter,* at 22.

[77] *Id.*

[78] *See* paragraphs (c)(2)(vi)(E), (c)(2)(vi)(F), (c)(2)(vi)(H), and (c)(2)(vi)(I) of Rule 15c3–1, as amended.

[79] *See* 17 CFR 240.15c3–1(c)(2)(vii).

the rule by allowing more positions to qualify for the lower haircuts.[80] The Commission notes that credit ratings and market data (such as credit spreads and yields) can serve as useful benchmarks for evaluating whether a broker-dealer's policies and procedures, as applied to the minimal amount of credit risk standard, are increasing the types of commercial paper, nonconvertible debt, and preferred stock positions to which it applies the lower haircuts as compared to the eliminated NRSRO credit rating standard.

The Commission is amending paragraph (c)(2)(vi)(E) of Rule 15c3–1 (relating to commercial paper haircuts), paragraphs (c)(2)(vi)(F)(*1*) and (c)(2)(vi)(F)(*2*) of Rule 15c3–1 (relating to nonconvertible debt haircuts), and paragraph (c)(2)(vi)(H) of Rule 15c3–1 (relating to preferred stock haircuts) by replacing references to NRSRO credit ratings with the alternative minimal amount of credit risk standard.[81] Consistent with the proposal, the final rule provides that a broker-dealer may apply the lower haircuts applicable to commercial paper (*i.e.,* between 0% and ½ of 1%), nonconvertible debt (*i.e.,* between 2% and 9%), and preferred stock (*i.e.,* 10%) if the security has only a minimal amount of credit risk.[82]

The Commission has made several modifications to its proposed rule text. First, the Commission has re-structured the rule by adding new paragraph (c)(2)(vi)(I) to specify requirements for the policies and procedures a broker-dealer must establish, document, maintain, and enforce for purposes of assessing whether a position has only a minimal amount credit risk under paragraphs (c)(2)(vi)(E), (c)(2)(vi)(F)(*1*), (c)(2)(vi)(F)(*2*), and (c)(2)(vi)(H).[83] Under the proposal, each of the paragraphs (*i.e.,* paragraphs (c)(2)(vi)(E), (c)(2)(vi)(F)(*1*), (c)(2)(vi)(F)(*2*), and (c)(2)(vi)(H)) separately provided that a broker-dealer must determine whether a position has only a minimal amount of credit risk pursuant to ''written policies and procedures the broker-dealer establishes, maintains, and enforces to assess creditworthiness.'' [84] Consistent with the proposal, each paragraph still requires that the security or money market instrument have only a minimal amount of credit risk before the lower haircut may be applied; however the reference to policies and procedures in each paragraph has been removed. Instead, new paragraph (c)(2)(vi)(I) of Rule 15c3–1 requires the broker-dealer to establish, document, maintain, and enforce policies and procedures to assess and monitor the creditworthiness of each security or money market instrument that are reasonably designed for the purpose of determining whether the position has only a minimal amount of credit risk.[85] Securities or money market instruments assessed to have only a minimal amount of credit risk also must meet the other non-credit rating conditions prescribed in Rule 15c3–1 in order to apply the lower haircuts under paragraphs (c)(2)(vi)(E), (c)(2)(vi)(F)(*1*), (c)(2)(vi)(F)(*2*), or (c)(2)(vi)(H).[86]

Under the final rule, new paragraph (c)(2)(vi)(I) of Rule 15c3–1 provides that in order to apply a deduction under paragraphs (c)(2)(vi)(E), (c)(2)(vi)(F)(*1*), (c)(2)(vi)(F)(*2*), or (c)(2)(vi)(H), the broker-dealer must assess the creditworthiness of the security or money market instrument pursuant to policies and procedures for assessing and monitoring creditworthiness that the broker-dealer establishes, documents, maintains, and enforces.[87] The Commission added the word ''monitoring'' to clarify that, after the initial determination by a broker-dealer, a position must continue to have only a minimal amount of credit risk in order to remain qualified for the lower haircut and that monitoring must be done in accordance with the firm's policies and procedures. Under Rule 15c3–1, a broker-dealer must at ''all times'' have and maintain an amount of net capital that is at least equal to the minimum amount of net capital required by the rule.[88] Consequently, the broker-dealer must monitor its securities and money market instrument positions in order to ensure that it is applying the appropriate haircuts to those positions. For example, under the NRSRO credit rating standard being eliminated today, a broker-dealer needed to monitor whether the positions it held continued to have the required credit ratings to apply the lower haircuts because credit rating agencies may adjust (*e.g.,* downgrade) their credit ratings. The same is true under the new minimal credit risk standard because the creditworthiness of a security or money market instrument can change over time and, consequently, a position that has only a minimal amount of credit risk at one point in time may not retain that status.

In the proposing release, the Commission requested comment on how often a broker-dealer should be required to update its assessments.[89] The Commission received one comment in response to this request.[90] The commenter stated that the frequency of review ''should be a function of a number of factors, including, e.g., the size and purpose of the broker-dealer's position in the fixed-income security, the volatility of business conditions within the relevant industry, the amount of fixed-income securities issued, and the frequency with which the securities trade.'' [91] The Commission generally agrees with the commenter that the frequency of review should depend on a variety factors such as those identified by the commenter. However, as discussed above, the requirement for a broker-dealer to maintain its required minimum amount of net capital is moment-to-moment. Consequently, a broker-dealer's policies and procedures for assessing whether an issuance of commercial paper, nonconvertible debt, or preferred stock

[80] As noted above, to qualify for the lower haircuts under the NRSRO credit rating standard being replaced today, commercial paper needed to be rated in one of the three highest rating categories by at least two NRSROs, nonconvertible debt needed to be rated in one of the four highest rating categories by at least two NRSROs, and preferred stock needed to be rated in one of the four highest rating categories by at least two NRSROs. For an example of one NRSRO's definitions of its four highest credit rating categories, *see* Standard & Poor's Ratings Definitions for long-term issuances *available at http://img.en25.com/Web/StandardandPoors/Ratings_Definitions.pdf.* Information about the credit rating categories of all the NRSROs can be obtained through the Forms NRSRO they file with the Commission and make publicly available. Links to these forms are *available at http://www.sec.gov/about/offices/ocr.shtml.*

[81] *See* paragraphs (c)(2)(vi)(E), (c)(2)(vi)(F), and (c)(2)(vi)(H) of Rule 15c3–1, as amended.

[82] *Id.*

[83] *See* paragraph (c)(2)(vi)(I) of Rule 15c3–1, as amended.

[84] *See Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26576.

[85] *See* paragraph (c)(2)(vi)(I) of Rule 15c3–1, as amended.

[86] Paragraph (c)(2)(vi)(E) of Rule 15c3–1, as amended, retains the non-credit rating conditions that the commercial paper must have a maturity at date of issuance not exceeding nine months exclusive of days of grace, or any renewal thereof, the maturity of which is likewise limited, and a fixed rate of interest, or be sold at a discount. *See* 17 CFR 240.15c3–1(c)(2)(vi)(E). Paragraph (c)(2)(vi)(F) of Rule 15c3–1, as amended, retains the non-credit rating conditions that the nonconvertible debt security must have a fixed rate of interest, a fixed maturity, and not be traded flat or in default as to principal or interest. *See* 17 CFR 240.15c3–1(c)(2)(vi)(F). Paragraph (c)(2)(vi)(H) of Rule 15c3–1, as amended, retains the non-credit rating conditions that the preferred stock must rank prior to all other classes of stock of the same issuer and not be in arrears as to dividends. *See* 17 CFR 240.15c3–1(c)(2)(vi)(H). *See also* 17 CFR 240.15c3–1(c)(2)(vii) (establishing a 100% deduction for securities for which there is no ready market).

[87] *See* paragraph (c)(2)(vi)(I) of Rule 15c3–1, as amended.

[88] *See* 17 CFR 240.15c3–1(a).

[89] *See Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26554.

[90] *See SIFMA Letter.*

[91] *Id.* at 21.

has only a minimal amount of credit risk must include a process that is designed to ensure that its credit determinations are current, and address the frequency with which the broker-dealer reviews and reassesses its credit determinations. For example, a broker-dealer's policies and procedures could require more frequent reassessments in the case of securities or money market instruments that are close to the line between having only a minimal amount of credit risk and having a greater level of credit risk or that are subject to macroeconomic conditions or issuer specific events that could have an impact on credit risk. In addition, a higher haircut must be taken when a security or money market instrument no longer has only a minimal amount of credit risk. The Commission expects that a broker-dealer's process for monitoring its credit determinations will be customized to the size and activities of the firm to ensure that it maintains the required amount of net capital at ''all times.'' [92]

The Commission also modified the proposed rule text relating to policies and procedures by including in new paragraph (c)(2)(vi)(I) of Rule 15c3–1 the qualifier that the policies and procedures must be ''reasonably designed'' for the purpose of assessing creditworthiness.[93] As noted above, one commenter raised a concern that Commission and SRO examiners would ''second guess'' broker-dealer credit assessments and stated that the regulatory focus on compliance with the rule should be on the ''reasonableness'' of a firm's policies and procedures for assessing creditworthiness.[94] The Commission agrees that the starting point for reviewing whether a firm is in compliance with the amendments should be to evaluate the reasonableness of the firm's policies and procedures in light of the firm's circumstances (*e.g.,* the size of the broker-dealer and the types and sizes of the positions typically held by the broker-dealer). In this regard, the policies and procedures must specify with sufficient detail the steps the broker-dealer will take in performing a credit assessment so that Commission and SRO examiners can evaluate them.

However, the Commission also modified the final rule to add new text that provides that policies and procedures that are reasonably designed ''should result in assessments of creditworthiness that typically are consistent with market data.'' [95] In particular, this standard for evaluating the reasonableness of a broker-dealer's policies and procedures will require examiners to compare market data (*e.g.,* external factors such as credit spreads or yields) with the broker-dealer's determinations that a security or money market instrument has only a minimal amount of credit risk. This provision is designed to address concerns raised by commenters that the proposed minimal amount of credit risk standard was too subjective.[96] Commenters raised concerns about requiring the use of a subjective standard because, among other things, it presents an inherent conflict of interest, is complicated, could reduce liquidity, and could result in uncertainty on the part of market participants.[97] Requiring a broker-dealer's policies and procedures to produce credit risk determinations that typically are consistent with market data should mitigate concerns about potential consequences of the subjectivity inherent in the final rule. Furthermore, as explained throughout this release, a broker-dealer can make its credit risk determination pursuant to policies and procedures that specify the use of a small number of objective factors and, if a broker-dealer avails itself of this option, it should help the broker-dealer create a less-complicated methodology that aligns with market data, therefore easing the concerns of commenters.

Notwithstanding the reasonableness of a broker-dealer's policies and procedures, examiners may still question a broker-dealer's credit risk determination, and are particularly likely to question a determination related to large concentrated positions or that is not consistent with market data. In addition, if a broker-dealer incorrectly determines pursuant to paragraph (c)(2)(vi)(I) of Rule 15c3–1 that a security has only a minimal amount of credit risk, the broker-dealer could be in violation of Rule 15c3–1 to the extent the appropriate larger haircut would put the broker-dealer below the required minimum amount of net capital.[98] Thus, a broker-dealer would need to be able to support each credit determination it makes in the context of a Commission or SRO examination. If the broker-dealer's determination that a position has only a minimal amount of credit risk is not consistent with market data, that result would not necessarily be dispositive that the position is not entitled to the lower haircut. However, the broker-dealer would have a high burden to demonstrate to examiners that the position has only a minimal amount of credit risk.

When assessing whether a security or money market instrument has only a minimal amount of credit risk for purposes of Rule 15c3–1, a broker-dealer could consider pursuant to the policies and procedures it establishes, documents, maintains, and enforces the following factors, to the extent appropriate:

- Credit spreads (*i.e.,* whether it is possible to demonstrate that a position in commercial paper, nonconvertible debt, and preferred stock has only a minimal amount of credit risk based on the spread between the security's yield and the yield on Treasury or other securities, or based on the spreads of credit default swaps that reference the security or money market instrument);
- Securities-related research (*i.e.,* whether providers of research about securities or money market instruments believe the issuer of the security or money market instrument will be able to meet its financial commitments, generally, or specifically, with respect to securities or money market instruments held by the broker-dealer);
- Internal or external credit risk assessments (*i.e.,* whether credit assessments developed internally by the broker-dealer or externally by a credit rating agency, irrespective of its status as an NRSRO, express a view as to the credit risk associated with a particular security or money market instrument of the issuer thereof);
- Default statistics (*i.e.,* whether providers of credit information relating to securities or money market instruments express a view that specific securities or money market instruments (or their issuers) have a probability of default consistent with other securities or money market instruments that have only a minimal amount of credit risk);
- Inclusion in an index (*i.e.,* whether a security, money market instrument, or the issuer of a security or money market instrument, is included as a component of a recognized index of instruments that have only a minimal amount of credit risk);
- Enhancements and priorities (*i.e.,* the extent to which a security or money market instrument is covered by credit enhancements, such as overcollateralization and reserve accounts, or has priority under

[92] *See* 17 CFR 240.15c3–1(a).

[93] *See* paragraph (c)(2)(vi)(I) of Rule 15c3–1, as amended.

[94] *SIFMA Letter,* at 19.

[95] *See* paragraph (c)(2)(vi)(I) of Rule 15c3–1, as amended.

[96] *Bond Dealers Letter,* at 2–3; *SIFMA Letter,* at 3.

[97] *Bond Dealers Letter,* at 2; *SIFMA Letter,* at 3.

[98] Calculating a haircut incorrectly also could cause the broker-dealer to file incorrect reports with the Commission under Rule 17a–5. *See* 17 CFR 240.17a–5 (requiring broker-dealers to periodically file financial reports that, among other things, contain computations of net capital).

applicable bankruptcy or creditors' rights provisions);

- Price, yield and/or volume (*i.e.,* whether the price and yield of a security or money market instrument or a credit default swap that references the security or money market instrument are consistent with other securities or money market instruments that the broker-dealer has determined have only a minimal amount of credit risk and whether the price resulted from active trading); and
- Asset class-specific factors (*e.g.,* in the case of structured finance products, the quality of the underlying assets).

The Commission does not intend this list of factors to be exhaustive or mutually exclusive. For example, other factors may be appropriate for assessing creditworthiness and, in particular, whether a position has only a minimal amount of credit risk.

As noted above, several commenters identified additional factors that they believe would be appropriate for purposes of assessing whether a security or money market instrument has only a minimal amount of credit risk and one commenter suggested making certain factors mandatory.[99] Some of these factors, such as the term to maturity of the security or money market instrument, are already factored into Rule 15c3–1 and therefore do not need to be specifically added to the list.[100] The Commission does not believe other factors should be added because the list is not meant to be exhaustive and broker-dealers should tailor their policies and procedures for assessing credit risk to their particular circumstances and specify in their policies and procedures those factors they deem appropriate, which may include factors that are not on the list above.[101] In addition, the Commission recognizes that a broker-dealer's policies and procedures may specify the use of different factors, different sets of factors, or different combinations of factors depending on the characteristics of the security or money market instrument being assessed, the amount of time the broker-dealer intends to hold the position, and the size of the position, among other things. Further, the Commission does not expect that in order for a broker-dealer's policies and procedures to be ''reasonably designed'' that they must specify the use of every factor, or any particular factor, on the list. Certain factors, such as credit spreads, may not be applicable for bonds that are thinly traded. Thus, mandating that factor, or any other factor, would not necessarily help a broker-dealer make a creditworthiness determination. Instead, each broker-dealer should analyze its unique situation when designing its policies and procedures, including, for example, its size, the amount of proprietary trading by the broker-dealer in commercial paper, nonconvertible debt, and preferred stock, and the size and characteristics of the positions the firm typically holds, among other things.

Under the amendments, a broker-dealer must apply a higher deduction, such as the 15% ''catchall'' haircut, on a proprietary position in commercial paper, nonconvertible debt, and preferred stock if the firm determines the security has more than a minimal amount of credit risk or the firm opts not to have policies and procedures to assess the creditworthiness of the class of security or money market instrument.[102] Moreover, if the commercial paper, nonconvertible debt, or preferred stock held by the broker-dealer does not trade in a ready market, the broker-dealer must apply a 100% haircut irrespective of the firm's credit risk determination.[103]

Under today's amendments, and consistent with the proposed amendments, a broker-dealer must preserve for a period of not less than three years, the first two years in an easily accessible place, the policies and procedures that the broker-dealer establishes, documents, maintains, and enforces for assessing and monitoring the credit risk of commercial paper, nonconvertible debt, and preferred stock. This requirement is codified in new paragraph (b)(13) of Rule 17a–4.[104]

The amendments do not require a broker-dealer to maintain a record of each of its credit risk determinations for purposes of Rule 15c3–1.[105] However, a broker-dealer would need to be able to support each of its credit risk determinations both for internal risk management purposes and in the context of a Commission or SRO examination. A broker-dealer should maintain documentation of its credit risk determinations for this purpose. Alternatively, a firm that maintains or can access the data, information, and inputs used to make a credit risk determination could be in a position to replicate the original credit risk determination using the same process, information, and inputs employed to make the original determination.[106] For example, if a broker-dealer uses market data to assess creditworthiness, it should be able to access information showing the data as of the date the credit risk determination was made.[107] A broker-dealer that uses a model with multiple inputs should be able to replicate the model output upon request or maintain a record of the model output as of the date of the original credit risk determination.

The Commission recognizes that requiring a broker-dealer to make and maintain a record of each credit risk determination, as suggested by one commenter,[108] may help facilitate examinations of broker-dealers, but the Commission believes at this time that requiring broker-dealers to maintain a record of every credit risk determination could be burdensome in light of the benefits expected to be obtained. For example, a broker-dealer may make multiple determinations while assessing and monitoring the creditworthiness of a particular security. If the broker-dealer reaches the same result time after time

[99] *Better Markets Letter,* at 6 (suggesting that the list ''be more comprehensive'' and include factors such as the nature of the issuer, the terms of the security, and the financial and regulatory context in which the issuer is operating); *Id.* at 3 (''the use of credit spreads and/or inclusion of an index should be the objective standard used to determine creditworthiness of these securities''); *CFA Institute Letter,* at 4 (suggesting the addition of ''term to maturity'' and ''concentration of credit risk'' as factors on the list).

[100] *See, e.g.,* 17 CFR 15c3–1(c)(2)(vi)(F)(*1*) (nonconvertible debt securities must have a ''fixed maturity date,'' among other factors, in order to qualify for a reduced haircut).

[101] One commenter agreed with the Commission. *SIFMA Letter,* at 20.

[102] *See* paragraph (c)(2)(vi)(I) of Rule 15c3–1, as amended; 17 CFR 240.15c3–1(c)(2)(vi)(J). If a broker-dealer chooses to apply the net capital deduction under paragraph (c)(2)(vi)(J) of Rule 15c3–1 instead of making an assessment of the creditworthiness of each security, the broker-dealer will not be required to have policies and procedures to assess a security's creditworthiness for purposes of applying the haircuts prescribed in paragraphs (c)(2)(vi)(E), (c)(2)(vi)(F)(*1*), (c)(2)(vi)(F)(*2*), or (c)(2)(vi)(H) of Rule 15c3–1.

[103] *See* 17 CFR 240.15c3–1(c)(2)(vii). As noted above, the term *ready market* is defined in Rule 15c3–1 as ''a market in which there exists independent bona fide offers to buy and sell so that a price reasonably related to the last sales price or current bona fide competitive bid and offer quotations can be determined for a particular security almost instantaneously and where payment will be received in settlement of a sale at such price within a relatively short time conforming to trade custom.'' 17 CFR 240.15c3–1(c)(11).

[104] *See* paragraph (b)(13) of Rule 17a–4, as amended.

[105] Paragraph (b)(5) of Rule 17a–4 provides, in pertinent part, that a broker-dealer shall preserve for a period of not less than three years (the first two years in an easily accessible place) all trial balances and computations of aggregate indebtedness and net capital (and working papers in connection therewith). *See* 17 CFR 240.17a–4(b)(5). Working papers relating to credit risk determinations made for the purposes of computing net capital under Rule 15c3–1 will need to be preserved under this provision of Rule 17a–4. *Id.*

[106] *See SIFMA Letter,* at 22.

[107] Although not required by today's amendments, a broker-dealer could choose to keep a record of the market data it used to make the creditworthiness determination.

[108] *See Better Markets Letter,* at 7–8.

showing that the security in question has only a minimal amount of credit risk, the benefits of keeping every determination for three years, when the broker-dealer has the ability to replicate the relevant determination for an examiner, could create costs that provide little benefits, given the examiner will have access to the replicated credit risk determinations. Furthermore, if market data and other external factors (*e.g.,* external credit assessments and analysis), strongly support the broker-dealer's assessment that a security has only a minimal amount of credit risk, retaining a record of the credit risk determination may not provide any incremental benefit to examiners. A broker-dealer that can replicate through application of its policies and procedures its original analysis to explain the basis of a credit risk determination should be in a position to demonstrate to examiners whether it is following its policies and procedures, and whether those policies and procedures are reasonably designed and effective in producing credit assessments that typically are consistent with market data.

The Commission is cognizant of the potential conflict of interest inherent in a requirement that relies to some extent on the subjective judgment of the broker-dealer to determine whether a lower haircut should apply to a commercial paper, nonconvertible debt, or preferred stock position, as noted by some commenters.[109] For example, a broker-dealer may want to hold securities with higher yields to earn more interest but at the same time apply lower haircuts to the positions to increase its net capital. This could bias the broker-dealer's credit assessment towards finding the security has only a minimal amount of credit risk. As an initial matter, if a broker-dealer incorrectly determines a position has only a minimal amount of credit risk and applies a lower haircut, it could lead to the firm failing to maintain the minimum amount of required net capital in violation of the rule. As discussed above, the final rule provides that policies and procedures that are reasonably designed should result in assessments of creditworthiness that typically are consistent with market data.[110] This provides objective benchmarks (*i.e.,* market data) to use to evaluate the broker-dealer's policies and procedures. If a broker-dealer has policies and procedures in place that are reasonably designed under the rule, and those policies and procedures are followed, the potential for bias to be a part of the assessment process should be mitigated. The Commission also expects that this potential conflict of interest will be mitigated by the Commission and SRO examination process, during which Commission and SRO examiners will review the reasonableness of broker-dealers' policies and procedures, the assessments that result from those policies and procedures, and the firms' adherence to the policies and procedures.[111]

The Commission also is aware of the likelihood that broker-dealers may reach different conclusions when assessing whether a particular position has only a minimal amount of credit risk,[112] or may reach conclusions that are contrary to market data. The Commission expects that Commission and SRO staff will examine for these types of differences and raise questions when a broker-dealer consistently determines that positions have only a minimal amount of credit risk notwithstanding the fact that external benchmarks (*e.g.,* market data) in the factors listed above indicate otherwise. A determination that a position has only a minimal amount of credit risk that is contrary to some market data points and factors would not necessarily mean that the broker-dealer has failed to comply with the rule, but the broker-dealer would have a higher hurdle to overcome to demonstrate that its credit risk determination is correct. The Commission also notes that if a broker-dealer determines that a security or money market instrument has only a minimal amount of credit risk when the position actually does not meet that standard, and applies a lower haircut, the broker-dealer's net capital may be less than its minimum net capital requirement in which case the broker-dealer would be in violation of the rule.[113]

The Commission understands, as noted by commenters, that the amount of resources broker-dealers can allocate toward making assessments of creditworthiness for purposes of Rule 15c3–1 will differ across broker-dealers and expects that this difference will be reflected in the policies and procedures for assessing creditworthiness established by the firms.[114] For example, a small broker-dealer may not have the resources to support a credit risk department comprised of analysts that perform internal credit assessments. In this case, the firm may establish a process for assessing creditworthiness that relies more on external factors, such as credit spreads, default statistics, and credit analysis. A broker-dealer with a large portfolio of debt securities may instead use an internal approach for assessing creditworthiness, which takes into consideration a multitude of factors, such as default probabilities, expected and unexpected losses, time effects, default correlations, and loss distributions, among other things. The Commission also anticipates that some broker-dealers, particularly those that hold few positions, may elect not to devote resources toward performing credit risk analysis and maintaining policies and procedures, and instead will apply a greater haircut to their proprietary positions in commercial paper, nonconvertible debt, and preferred stock, as permitted by the rule.

Finally, as discussed above, a broker-dealer (rather than its parent or an affiliate) must establish, document, maintain, and enforce the policies and procedures for assessing whether a position has only a minimal amount of credit risk.[115] This does not mean that a broker-dealer cannot incorporate into its own policies and procedures the credit policies and procedures used by its parent or an affiliate. However, the broker-dealer must establish, document, maintain, and enforce its own policies and procedures and apply them itself in making creditworthiness determinations. It may not simply rely on determinations made by its parent or an affiliate.

b. Appendix A to Rule 15c3–1

i. Proposal

Appendix A to Rule 15c3–1 permits broker-dealers to employ a standardized theoretical option pricing model to determine a potential loss for a portfolio of listed options positions and related positions to compute a single haircut for the group of positions.[116] Under Appendix A, a broker-dealer groups the options and related positions in a portfolio and stresses the current market

[109] *Better Markets Letter,* at 5–6; *Bond Dealers Letter,* at 2; *CFA Institute Letter,* at 4.

[110] *See* paragraph (c)(2)(vi)(I) of Rule 15c3–1, as amended.

[111] As noted above, broker-dealers that do not keep detailed records of their credit risk determinations can replicate those determinations for Commission and SRO examiners to demonstrate that they followed their policies and procedures for assessing and monitoring creditworthiness.

[112] *Bond Dealers Letter,* at 3; *SIFMA Letter,* at 20.

[113] As noted above, applying an incorrect haircut also could cause the broker-dealer to file incorrect reports with the Commission under Rule 17a–5. *See* 17 CFR 240.17a–5 (requiring broker-dealers to periodically file financial reports that, among other things, contain computations of net capital).

[114] *See Bond Dealers Letter,* at 3; *SIFMA Letter,* at 18.

[115] *See SIFMA Letter,* at 21.

[116] *See* 17 CFR 240.15c3–1a(b)(1). Broker-dealers also may elect a strategy-based methodology. *See* 17 CFR 240.15c3–1a(b)(2).

price for each position at various equidistant points along a range of positive and negative potential future market movements, using an approved theoretical option pricing model that satisfies certain conditions specified in the rule.[117] Positions that have more potential price volatility must be stressed across a wider range of positive and negative potential future market movements than positions with lower price volatility.[118] For example, a broker-dealer other than a non-clearing option specialist or market maker must employ a range of potential future market movements for major market foreign currencies of (±) 6%, whereas the range for all other foreign currencies is (±) 20%.[119] Thus, major market foreign currency options receive more favorable treatment than options on all other currencies when using theoretical option pricing models to compute net capital deductions.[120]

Prior to today's amendments, the rule defined the term *major market foreign currency* to mean ''the currency of a sovereign nation whose short term debt is rated in one of the two highest categories by at least two nationally recognized statistical rating organizations and for which there is a substantial inter-bank forward currency market.'' [121] Further, the rule provided that ''the European Currency Unit (ECU) shall be deemed a major market foreign currency.'' [122]

With respect to the definition of *major market foreign currency,* the Commission proposed to remove the phrase ''whose short-term debt is rated in one of the two highest categories by at least two nationally recognized statistical rating organizations.'' [123] The proposed change would modify the definition to include foreign currencies only ''for which there is a substantial inter-bank forward currency market.'' [124] The Commission also proposed to eliminate the specific reference in the rule to the European Currency Unit (''ECU''), which was the only currency explicitly identified in the rule as a major market foreign currency for the purposes of Appendix A.[125] As the Commission stated in the proposing release, because of the establishment of the euro as the official currency of the euro-zone, a specific reference to the ECU was no longer needed.[126] The Commission also stated that a specific reference to the euro was not necessary, as it is a foreign currency with a substantial inter-bank forward currency market.[127]

ii. Comments

The Commission received two comment letters in response to its request for comment.[128] One commenter supported the proposed definition of the term *major market foreign currency,* stating that ''the proposed definition is sufficient to allow broker-dealers to determine what currencies are 'major market foreign currencies.' '' [129] Both commenters stated that the Commission should create a list of major market foreign currencies and update it periodically to clarify the new definition in Appendix A.[130] One commenter suggested that if the Commission chooses not to create a list of major market foreign currencies, it should propose an alternative measure of creditworthiness and define the term as one where the currency is issued by a nation whose sovereign debt presents ''minimal credit risk.'' [131]

iii. Final Rule

For the reasons described below, the Commission is adopting the amendments to Appendix A as proposed.[132] Specifically, the Commission is removing from the definition of *major market foreign currency* the phrase ''whose short-term debt is rated in one of the two highest categories by at least two nationally recognized statistical rating organizations.'' [133] The change modifies the definition to include foreign currencies only ''for which there is a substantial inter-bank forward currency market.'' [134] Also, the Commission is eliminating the specific reference in the rule to the ECU, which was identified, by rule, as the only major market foreign currency for the purposes of Appendix A.[135] As the Commission noted in the proposing release, specific reference to the ECU is no longer needed because the euro has been established as the official currency of the euro-zone.[136] Further, the specific reference to the euro is not necessary as it is a foreign currency with a substantial inter-bank forward currency market, consistent with the rule as amended.

In order to retain a degree of flexibility, the Commission is not codifying in the rule a list of currencies that meet the definition of *major market foreign currency* though some commenters requested such a list. However, broker-dealers may treat a foreign currency as a major market foreign currency for the purposes of Appendix A if the currency is a major foreign currency for purposes of applying a 6% (rather than 20%) haircut under Rule 15c3–1. Currently, under a staff interpretation, broker-dealers are subject to a 6% (rather than 20%) unhedged currency risk exposure haircut on foreign currency balances and positions in the euro, the British pound, the Swiss franc, the Canadian dollar, and the Japanese yen.[137] The Commission believes the staff interpretation identifies currencies that all meet the definition of *major market foreign currency* for the purposes of Appendix A as they all have a substantial inter-bank forward currency market. Consequently, broker-dealers may treat these currencies as major market foreign currencies under Appendix A. By treating these currencies as major market foreign currencies, the haircuts applicable to foreign currencies under Rule 15c3–1 are more closely aligned with the haircuts applicable to options on the same foreign currencies under

[117] *See* 17 CFR 240.15c3–1a(b)(1). Presently, there is only one theoretical options pricing model that has been approved for this purpose.

[118] *See* 17 CFR 240.15c3–1a(b)(1)(iii).

[119] *See* 17 CFR 240.15c3–1a(b)(1)(iii)(B) through (C). A broker-dealer that is a non-clearing option specialist or market maker must employ a range of potential future market movements for major market foreign currencies of (±) 4% (*i.e.,* less than the (±) 6% required of other broker-dealers). 17 CFR 240.15c3–1a(b)(1)(iv)(A).

[120] *See* 17 CFR 240.15c3–1a(b)(1)(iii)(B) through (C) and (b)(1)(iv)(A).

[121] *Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26554–26555.

[122] *Id.*

[123] *Id.*

[124] *Id.*

[125] *Id.*

[126] *Id.*

[127] *Id.*

[128] *See Better Markets Letter; CFA Institute Letter; see also Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26555.

[129] *See CFA Institute Letter,* at 4 (''[T]he existence of a substantial inter-bank forward currency market indicates market interest and the existence of market oversight and thus provides a strong indication of market sentiment about the quality of currencies within that definition.'').

[130] *Better Markets Letter,* at 9; *CFA Institute Letter,* at 5.

[131] *See Better Markets Letter,* at 9.

[132] *See* paragraph (b)(1)(i)(C) of Rule 15c3–1a, as amended.

[133] *Id.*

[134] *Id.*

[135] *Id.*

[136] *Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26555.

[137] *See FINRA Interpretations of Financial and Operational Rules,* Rule 15c3–1(c)(2)(vi)/08, *available at http://www.finra.org/web/groups/industry/@ip/@reg/@rules/documents/interpretationsfor/p037763.pdf,* p. 406 (publishing the staff's interpretation). A 20% haircut applies to unhedged currency risk exposure on all other foreign currency balances and positions. *Id.* These interpretations are provided to FINRA from the Commission staff in the Division of Trading and Markets. Broker-dealers can also seek assurance as to whether another foreign currency meets the definition of *major market foreign currency* by, for example, requesting guidance from the staff.

Appendix A.[138] Given this interpretation identifying certain foreign currencies that meet the definition of *major market foreign currency,* the Commission believes it has addressed the concern raised by one commenter that, in the absence of a list, the Commission should define the term as one where the currency is issued by a nation whose sovereign debt presents minimal credit risk.[139]

c. Appendix E to Rule 15c3–1

i. Proposal

Certain broker-dealers (''ANC broker-dealers'') are approved by the Commission to use internal value-at-risk (''VaR'') models to determine market risk charges for proprietary securities and derivatives positions and to take a credit risk charge in lieu of a 100% charge for unsecured receivables related to OTC derivatives transactions.[140] Specifically, under Appendix E to Rule 15c3–1, ANC broker-dealers are permitted to add back to net worth uncollateralized receivables from counterparties arising from OTC derivatives transactions (*i.e.,* they can add back the amount of the uncollateralized current exposure).[141] Instead of the 100% deduction that applies to most unsecured receivables under Rule 15c3–1, ANC broker-dealers are permitted to take a credit risk charge based on the uncollateralized credit exposure to the counterparty.[142] In most cases, the credit risk charge is significantly less than a 100% deduction, since it is a percentage of the amount of the receivable that otherwise would be deducted in full. ANC broker-dealers are permitted to use this approach because they are required to implement processes for analyzing credit risk to OTC derivative counterparties and to develop mathematical models for estimating credit exposures arising from OTC derivatives transactions.

Under Appendix E, the credit risk charge is the sum of three calculated amounts: (1) A counterparty exposure charge; (2) a concentration charge if the current exposure to a single counterparty exceeds certain thresholds; and (3) a portfolio concentration charge if aggregate current exposure to all counterparties exceeds certain thresholds.[143] The first component of the credit risk charge is the counterparty exposure charge.[144] The exposure charge for a given counterparty (other than a counterparty that is insolvent, in a bankruptcy proceeding, or in default of an obligation on its senior debt) is the credit equivalent amount of the ANC broker-dealer's exposure to the counterparty multiplied by an applicable credit risk weight factor and then multiplied by 8%.[145] The credit equivalent amount is the sum of the ANC broker-dealer's: (1) Maximum potential exposure (''MPE'') to the counterparty multiplied by a back-testing determined factor; and (2) current exposure to the counterparty.[146] The MPE amount is a charge to address potential future exposure and is calculated using the ANC broker-dealer's VaR model as applied to the counterparty's positions after giving effect to a netting agreement with the counterparty, taking into account collateral received from the counterparty, and taking into account the current replacement value of the counterparty's positions.[147] The current exposure amount is the current replacement value of the counterparty's positions after giving effect to a netting agreement with the counterparty and taking into account collateral received from the counterparty.[148] The counterparty exposure charge is the sum of the MPE and current exposure amounts multiplied by an applicable credit risk weight factor and then multiplied by 8%.[149] Appendix E to Rule 15c3–1 prescribes three standardized credit risk weight factors (20%, 50%, and 150%) for transactions with counterparties and, as an alternative, permits an ANC broker-dealer with Commission approval to use internal methodologies to determine appropriate credit risk weights to apply to counterparties.[150] A higher percentage credit risk weight factor results in a larger counterparty exposure charge amount. Prior to today's amendments, ANC broker-dealers were permitted to use NRSRO credit ratings or internally derived credit ratings to determine the appropriate risk weight factor.

The Commission proposed removing paragraphs (c)(4)(vi)(A) through (c)(4)(vi)(D) of Appendix E, which specify the appropriate risk weight factor of counterparties based on NRSRO credit ratings.[151] Consequently, under the proposal, an ANC broker-dealer would need to determine credit risk charges using internal credit ratings or to take a 100% capital charge with respect to the exposure to the counterparty.[152] By removing the option to use NRSRO credit ratings, a broker-dealer that applies to use the approach set forth in Appendix E would need to describe how it will determine the applicable counterparty credit risk charge based on internal credit ratings as part of its initial application to the Commission.[153]

ii. Comments

The Commission received two comments in response to its request for comment.[154] One commenter supported the proposed removal of NRSRO credit ratings as an option but raised two concerns.[155] The commenter stated first that an internal model may not take into account concentration of risk with a specific counterparty, and second that ANC firms will apply low risk weights

[138] Treating the option consistently with the instrument underlying the option is supported by Appendix A. For example, under Appendix A, the range of potential future market movements that must be employed for a portfolio of equity positions with a ready market is (±) 15%. *See* 17 CFR 240.15c3–1a(b)(1)(iii)(A). Under Rule 15c3–1, the haircut that must be applied to an equity security with a ready market is 15%. *See* 17 CFR 240.15c3–1(c)(2)(vi)(J).

[139] *See Better Markets Letter,* at 9.

[140] *See* 17 CFR 240.15c3–1(a)(7); 17 CFR 240.15c3–1e. As part of the application to use internal models, an entity seeking to become an ANC broker-dealer must identify the types of positions it intends to include in its model calculation. *See* 17 CFR 240.15c3–1e(a)(1)(iii). After approval, an ANC broker-dealer must obtain Commission approval to make a material change to the model, including a change to the types of positions included in the model. *See* 17 CFR 240.15c3–1e(a)(8). An ANC broker-dealer must maintain minimum tentative net capital of at least $1 billion and minimum net capital of at least $500 million. *See* 17 CFR 240.15c3–1(a)(7)(i). The Commission has proposed raising these requirements to $5 billion and $1 billion, respectively. *See Capital, Margin, and Segregation Requirements for Security-Based Swap Dealers and Major Security-Based Swap Participants and Capital Requirements for Broker-Dealers,* Exchange Act Release No. 68071 (Oct. 18, 2012), 77 FR 70213 (Nov. 23, 2012).

[141] *See* 17 CFR 240.15c3–1e(c).

[142] *See* 17 CFR 240.15c3–1e(c); 17 CFR 240.15c3–1(a)(7). The Commission has proposed narrowing this treatment of OTC derivatives exposures so that it would apply only to uncollateralized receivables from commercial end users arising from security-based swaps (*i.e.,* uncollateralized receivables from other types of counterparties would be subject to the 100% deduction from net worth). *See Capital, Margin, and Segregation Requirements for Security-Based Swap Dealers and Major Security-Based Swap Participants and Capital Requirements for Broker-Dealers,* 77 FR at 70240–70244.

[143] 17 CFR 240.15c3–1e(c).

[144] 17 CFR 240.15c3–1e(c)(1).

[145] *See* 17 CFR 240.15c3–1e(c)(1)(ii).

[146] *See* 17 CFR 240.15c3–1e(c)(4)(i). The amount of the factor is based on back-testing exceptions.

[147] *See* 17 CFR 240.15c3–1e(c)(4)(ii).

[148] *See* 17 CFR 240.15c3–1e(c)(4)(iii).

[149] *See* 17 CFR 240.15c3–1e(c)(1)(ii).

[150] *See* 17 CFR 240.15c3–1e(c)(4)(vi).

[151] *See Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26555–26556.

[152] *Id.*

[153] *Id.* at 26555.

[154] *Better Markets Letter; CFA Institute Letter; see also Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26555–26556.

[155] *CFA Institute Letter,* at 5–6.

to all but the most illiquid instruments.[156]

Another commenter suggested that the factors listed in the proposing release with respect to determining creditworthiness under Rule 15c3–1 should become part of Appendix E.[157] This commenter further argued that the factors each broker-dealer needed to use to make the determination should be explicitly stated in the rule.[158]

iii. Final Rule

The Commission is adopting the amendments to Appendix E to Rule 15c3–1 as proposed.[159] The amendments remove paragraphs (c)(4)(vi)(A) through (c)(4)(vi)(D) of Appendix E to Rule 15c3–1, which specify the appropriate risk weight factor based on NRSRO credit ratings.[160] By removing the provisions utilizing NRSRO credit ratings, the final rule requires an ANC broker-dealer to determine the appropriate risk weight factor using internal credit ratings or to take a 100% capital charge with respect to the exposure to the counterparty.[161]

All ANC broker-dealers calculate credit risk charges using internal credit ratings (rather than using NRSRO credit ratings approach) or take a 100% capital charge with respect to the exposure to the counterparty risk.[162] Consequently, removing the option to use NRSRO credit ratings will not have an immediate effect on these broker-dealers. A broker-dealer that applies to become an ANC broker-dealer will need to describe how it will determine internal credit ratings for the purpose of determining the applicable credit charges for counterparty risk in its application to the Commission.

In taking this action, the Commission has considered the views of commenters[163] and determined that whether a model adequately considers risks associated with a counterparty or a specific instrument is a concern that should be addressed during the initial review of the ANC broker-dealer's model, as well as during the monitoring and examination of the firm.[164] The amendments also do not incorporate the minimal amount of credit risk standard from Rule 15c3–1 into Appendix E, as suggested by one commenter.[165] This standard is replacing a binary NRSRO credit rating standard under which the application of a lower or higher haircut amount depends on whether the commercial paper is rated in the top three rating categories and the nonconvertible debt and preferred stock is rated in the top four rating categories. Consequently, a given instrument either meets the requirement to apply a lower haircut amount or is subject to the higher amount. The NRSRO credit rating standard in Appendix E to Rule 15c3–1 is not binary in that there are three different credit risk weights (20%, 50%, and 150%) that are determined by three different levels of credit rating: The two highest rating categories; the third and fourth highest rating categories; and below the fourth highest rating. Thus, the minimal amount of credit risk standard would not be a suitable replacement for the NRSRO credit ratings standard because the minimal amount of credit risk standard, as drafted for Rule 15c3–1, would apply only to the second gradation (the third and fourth highest rating categories).[166]

In addition, as stated throughout this release, the Commission has determined not to mandate that a broker-dealer use any specific factor in its credit analysis. Consequently, the Commission does not believe it would be appropriate to codify the list of factors in the rule as suggested by one commenter.

d. Appendix F to Rule 15c3–1 and Form X–17A–5, Part IIB

i. Proposal

Similar to ANC broker-dealers, a type of limited purpose broker-dealer that deals solely in OTC derivatives (an ''OTC derivatives dealer'') is permitted, with Commission approval, to calculate net capital using internal models as the basis for taking market risk and credit risk charges in lieu of the standardized haircuts for classes of positions for which they have been approved to use VaR models.[167] Specifically, under Appendix F to Rule 15c3–1, OTC derivatives dealers are permitted to add back to net worth uncollateralized receivables from counterparties arising from OTC derivatives transactions (*i.e.,* they can add back the amount of the uncollateralized current exposure). Instead of the 100% deduction that applies to most unsecured receivables under Rule 15c3–1, OTC derivatives dealers are permitted to take a credit risk charge based on counterparty factors and concentration charges.[168] In most cases, the counterparty factors and concentration charges are significantly less than a 100% deduction, since the charges are a percentage of the amount of the receivable that otherwise would be deducted in full. OTC derivatives dealers are permitted to use this approach because they are required to implement processes for analyzing credit risk to OTC derivative counterparties and to develop mathematical models for estimating credit exposures arising from OTC derivative transactions.

Under Appendix F to Rule 15c3–1, OTC derivatives dealers are required to deduct from their net capital credit risk charges that take counterparty risk into consideration.[169] This charge has two parts and is computed on a counterparty-by-counterparty basis. First, for each counterparty with an investment or speculative grade rating, an OTC derivatives dealer must take a net capital charge equal to the net replacement value in the account of the counterparty (''net replacement value'') multiplied by 8%, and further multiplied by a counterparty factor.[170] As part of this deduction, the OTC derivatives dealer must apply a counterparty risk weight factor of either 20%, 50%, or 100%.[171] Prior to today's amendments, the counterparty risk weight factor (*i.e.,* 20%, 50%, or 100%) was determined using either NRSRO

[156] *Id.*

[157] *Better Markets Letter,* at 10.

[158] *Id.*

[159] *See* paragraph (c)(4)(vi) of Rule 15c3–1e, as amended.

[160] *Id.*

[161] *Id.*

[162] Currently, there are six ANC broker-dealers: Barclays Capital Inc.; Citigroup Global Markets, Inc.; Goldman Sachs & Co.; J.P. Morgan Chase Securities LLC; Merrill Lynch Pierce Fenner & Smith Incorporated; and Morgan Stanley & Co. Incorporated.

[163] *CFA Institute Letter,* at 5; *Better Markets Letter,* at 10.

[164] *See, e.g.,* 17 CFR 15c3–1e(a)(1)(iv).

[165] *Better Markets Letter,* at 10.

[166] *See* 15 CFR 15c3–1e(c)(4)(vi)(B).

[167] *See* 17 CFR 240.15c3–1(a)(5); 17 CFR 240.15c3–1f. As part of the application to use internal models, an entity seeking to become an OTC derivatives dealer must identify the types of positions it intends to include in its model calculation. *See* 17 CFR 240.15c3–1f(a)(1)(ii). After approval, an OTC derivatives dealer must obtain Commission approval to make a material change to the model, including a change to the types of positions included in the model. *See* 17 CFR 240.15c3–f(a)(3). OTC derivatives dealers are exempt from certain broker-dealer requirements, including membership in an SRO (17 CFR 240.15b9–2), broker-dealer margin rules (17 CFR 240.36a1–1), and application of the Securities Investor Protection Act of 1970 (17 CFR 240.36a1–2). OTC derivatives dealers are subject to special requirements, including limitations on the scope of their securities activities (17 CFR 240.15a–1), specified internal risk management control systems (17 CFR 240.15c3–4), recordkeeping obligations (17 CFR 240.17a–3(a)(10)), and reporting responsibilities (17 CFR 240.17a–12). They are also subject to alternative net capital treatment (17 CFR 240.15c3–1(a)(5)). *See* 17 CFR 240.15a–1, Preliminary Note. The minimum net capital requirements for an OTC derivatives dealer are tentative net capital of at least $100 million and net capital of at least $20 million. *See* 17 CFR 240.15c3–1(a)(5) and (c)(15).

[168] *See* 17 CFR 240.15c3–1f(d); 17 CFR 240.15c3–1(a)(5).

[169] *See* 17 CFR 240.15c3–1f(d).

[170] *See* 17 CFR 240.15c3–1f(d)(2).

[171] *See* 17 CFR 240.15c3–1f(d)(2)(i) through (iii).

credit ratings or the firm's internal credit ratings.[172]

The second part of the credit risk charge consists of a concentration charge that applies when the net replacement value in the account of any one counterparty exceeds 25% of the OTC derivatives dealer's tentative net capital.[173] The concentration charge increases in relation to the OTC derivatives dealer's exposure to lower rated counterparties.[174] Prior to today's amendments, this concentration charge was also determined using either NRSRO credit ratings or the firm's internal credit ratings. Currently, OTC derivatives dealers do not use NRSRO credit ratings to determine their counterparty factors and concentration charges.

The Commission proposed to amend paragraphs (d)(2), (d)(3)(i), (d)(3)(ii), (d)(3)(iii), and (d)(4) of Appendix F to Rule 15c3–1, which permit the use of NRSRO ratings (as an alternative to internal credit ratings) to determine an OTC derivatives dealer's counterparty factors and concentration charges. Because the proposal would eliminate the option to use NRSRO credit ratings, a broker-dealer that applies to become an OTC derivatives dealer and operate under Appendix F will need, as part of its initial application, to request Commission approval to use internal credit ratings (as the option to use NRSRO credit ratings is being eliminated). The OTC derivatives dealer would need to describe how it will determine the applicable counterparty factors and concentration charges as part of its initial application to the Commission.

As part of its proposal, the Commission also proposed conforming amendments to the General Instructions to Form X–17A–5, Part IIB. This form constitutes the basic financial and operational report OTC derivatives dealers are required to file with the Commission. Under the heading ''Computation of Net Capital and Required Net Capital,'' the Commission proposed making conforming changes to the section ''Credit risk exposure.'' This section instructs an OTC derivatives dealer on how to compute the counterparty credit risk charges for purposes of the dealer's net capital computation. The proposed amendments to the instructions would eliminate references to NRSRO credit ratings for purposes of determining these charges.

ii. Comments

The Commission received two comments in response to its request for comment.[175] One commenter suggested that the Commission require OTC derivatives dealers to use counterparty factors similar to those proposed under Appendix E discussed above (*e.g.,* 20%, 50% or 150% risk weights based on internal credit ratings to determine capital deductions) and argued against requiring OTC derivatives dealers to reapply to the Commission to use internal credit ratings.[176] This commenter also expressed concern that an OTC derivatives dealer's internal model may not take into account concentration of risk with a specific counterparty.[177]

The second commenter suggested that the Commission ''supply an appropriate alternative standard of creditworthiness that derivatives dealers must apply'' such as ''an explicit set of factors that will appropriately gauge the credit risk associated with counterparties in derivatives transactions.'' [178]

iii. Final Rule

The Commission is adopting the amendments to Appendix F to Rule 15c3–1 as proposed.[179] Specifically, the amendments remove the use of NRSRO credit ratings from paragraphs (d)(2), (d)(3)(i), (d)(3)(ii), (d)(3)(iii), and (d)(4) of Appendix F to Rule 15c3–1, which, prior to today's amendments, permitted the use of NRSRO ratings when determining counterparty credit risk and concentration charges.[180] Because the amendments remove the option to use NRSRO credit ratings, a broker-dealer that applies to become an OTC derivatives dealer will need, as part of its initial application, to request Commission approval to use internal credit ratings (as the option to use NRSRO credit ratings is being eliminated). The applicant will need to describe how it will use internal credit ratings to determine the applicable credit risk charges for counterparty risk in its application to the Commission. The current OTC derivatives dealers will not need to seek new approval from the Commission.[181]

The Commission also is adopting the conforming amendments to the General Instructions to Form X–17A–5, Part IIB as proposed.

Consistent with the discussion above relating to Appendix E to Rule 15c3–1, the Commission has determined that whether a model adequately considers concentration risk with a specific counterparty is a concern that is best addressed during the initial review of, or an amendment to, an OTC derivatives dealer's model as well as during the monitoring and examination of the OTC derivatives dealer.[182] Further, as stated above, the current OTC derivatives dealers do not use NRSRO ratings to compute the credit risk and concentration charges under Appendix F. Thus, the amendments will not impact these firms.

The Commission is not adopting an alternative standard in the rule, such as the minimal amount of credit risk standard. As discussed above, the minimal amount of credit risk standard is replacing a binary NRSRO credit rating standard under which the application of a lower or higher haircut amount depends on whether the commercial paper is rated in the top three rating categories and the nonconvertible debt and preferred stock is rated in the top four rating categories. Consequently, a given instrument either meets the requirement to apply a lower haircut amount or is subject to the higher amount. The NRSRO credit rating standard in Appendix F to Rule 15c3–1 is not binary in that there are three ranges of credit ratings to determine the applicable risk weight factors and concentration charges: The two highest rating categories; the third and fourth highest rating categories; and below the fourth highest rating category. Thus, the minimal amount of credit risk standard would not be a suitable replacement for the credit risk charges required under Appendix F to Rule 15c3–1 because the minimal amount of credit risk standard, as drafted for Rule 15c3–1, would apply only to the second

[172] *See* 17 CFR 240.15c3–1f(d)(2) and (4).

[173] *See* 17 CFR 240.15c3–1f(d)(3).

[174] For counterparties that are highly rated, the concentration charge equals 5% of the amount of the net replacement value in excess of 25% of the OTC derivatives dealer's tentative net capital. 17 CFR 240.15c3–1f(d)(3)(i). The concentration charge for counterparties with ratings among the lowest rating categories would equal 50% of the amount of the net replacement value in excess of 25% of the OTC derivatives dealer's tentative net capital. 17 CFR 240.15c3–1f(d)(3)(iii).

[175] *CFA Institute Letter; Better Markets Letter; see also Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26556.

[176] *CFA Institute Letter,* at 6.

[177] *Id.*

[178] *Better Markets Letter,* at 10, n.15.

[179] *See* paragraph (d) of Rule 15c3–1f, as amended.

[180] *See* paragraphs (d)(2), (d)(3)(i), (d)(3)(ii), (d)(3)(iii), and (d)(4) of Rule 15c3–1f, as amended.

[181] Currently, four firms are operating pursuant to Appendix F to Rule 15c3–1. These firms are: Credit Suisse Capital LLC; Goldman Sachs Financial Markets, L.P.; Merrill Lynch Financial Markets, Inc.; and Natixis Derivatives Inc. Natixis Derivatives, Inc. filed a Form BDW on October 17, 2013.

[182] *See, e.g.,* 17 CFR 15c3–1f(a)(1)(ii); *see also CFA Institute Letter,* at 6.

range (the third and fourth highest rating categories).[183]

In addition, as stated throughout this release, the Commission has determined not to mandate that a broker-dealer use any specific factor in its credit analysis; instead, each firm will need to tailor its procedures for determining credit risk to the broker-dealer's business model.[184]

e. Appendix G to Rule 15c3–1

Appendix G to Rule 15c3–1 provides that broker-dealers may use the ANC computation only if their ultimate holding companies agree to provide the Commission with additional information about the financial condition of the holding company and its affiliates.[185] Appendix G is intended to provide the Commission with certain information to assess the financial and operational health of the ultimate holding company and its potential impact on the risk exposure of the broker-dealer.[186] Paragraph (a) of Appendix G sets forth a methodology for computing allowable capital and allowances for market and credit risk at the consolidated holding company level. One aspect of calculating credit risk in Appendix G provided that those firms must use credit ratings in accordance with the applicable provisions of Appendix E. Since those provisions in Appendix E are being deleted, the Commission proposed deleting the corresponding references to those provisions in Appendix G.[187] Specifically, the Commission proposed to delete references in paragraph (a)(3)(i)(F) of Appendix G that correspond to the provisions of Appendix E that the Commission is deleting as described above.[188]

The Commission received no comments addressing these changes.[189] The Commission is amending Appendix G to Rule 15c3–1 as proposed.[190] Accordingly, the Commission is adopting a conforming amendment to Appendix G that deletes references in paragraph (a)(3)(i)(F) of Appendix G that correspond to the provisions of Appendix E that the Commission is deleting as described above.[191]

f. Exhibit A to Rule 15c3–3

Rule 15c3–3 (the ''Customer Protection Rule'') under the Exchange Act is designed to protect customer funds and securities held by broker-dealers.[192] To meet this objective, Rule 15c3–3 requires a broker-dealer that maintains custody of customer securities and cash (a ''carrying broker-dealer'') to take two primary steps to safeguard these assets. The steps are designed to protect customers by segregating their securities and cash from the broker-dealer's proprietary business activities. If the broker-dealer fails financially, the securities and cash should be readily available to be returned to the customers. In addition, if the failed broker-dealer is liquidated in a formal proceeding under the Securities Investor Protection Act of 1970, the securities and cash should be isolated and readily identifiable as customer property and, consequently, available to be distributed to customers ahead of other creditors.[193]

The first step to safeguard customer assets under Rule 15c3–3 requires a carrying broker-dealer to maintain possession or control of all fully paid and excess margin securities of its customers.[194] Physical possession or control means the broker-dealer must hold these securities in one of several locations specified in Rule 15c3–3 and free of liens or any other interest that could be exercised by a third party to secure an obligation of the broker-dealer.[195] Permissible locations include a bank, as defined in section 3(a)(6) of the Exchange Act, and a clearing agency.[196] A broker-dealer must make a daily determination of the amount of fully paid and excess margin securities it holds for customers and compare it to the amount actually held in the permissible locations in order to comply with this aspect of the rule.[197]

The second step covers customer funds and requires that a carrying broker-dealer must maintain a reserve of cash or qualified securities in one or more accounts at a bank that is at least equal in value to the net cash owed to customers and the amount of cash obtained from the use of customer securities.[198] The account must be titled ''Special Account for the Exclusive Benefit of Customers of the Broker-Dealer'' (''customer reserve account'').[199] The amount of cash and/or qualified securities that must be kept in the customer reserve account is computed pursuant to a formula set forth in Exhibit A to Rule 15c3–3.[200] Under the Exhibit A formula, the broker-dealer adds customer credit items (*e.g.,* cash in customer securities accounts) and then subtracts from that amount customer debit items (*e.g.,* margin loans).[201] If credit items exceed debit items, the net amount must be on deposit in the customer reserve account in the form of cash and/or qualified securities.[202] If the debits exceed credits, no deposit is necessary. Funds deposited in a customer reserve account cannot be withdrawn until the broker-dealer completes another computation that shows that the broker-dealer has on deposit more funds than the reserve formula requires.

Under Note G to Exhibit A, a carrying broker-dealer may include margin collateral for transactions in security futures products as a debit in its reserve formula computation if that margin collateral is required and on deposit at a clearing agency or derivatives clearing organization that meets at least one of four conditions: (1) The clearing agency or derivatives clearing organization maintains the highest investment-grade rating from an NRSRO; (2) the clearing agency or derivatives clearing organization maintains security deposits from clearing members in connection with regulated options or futures transactions and assessment power over member firms that equal a combined total of at least $2 billion, at least $500 million of which must be in the form of security deposits; (3) the clearing agency or derivatives clearing organization maintains at least $3 billion in margin deposits; or (4) the clearing agency or derivatives clearing organization obtains an exemption from the Commission.

Margin collateral that is posted for customer positions in security futures products constitutes an unsecured receivable from the clearing agency or derivatives clearing organization. Therefore, requiring a clearing agency or a derivatives clearing organization to meet certain minimum creditworthiness criteria before margin collateral deposited with that entity may be included as a debit in a broker-dealer's customer reserve formula is consistent with the customer protection function of Rule 15c3–3 because the debit offsets any credits when computing the customer reserve deposit requirement.

[183] *See* 17 CFR 240.15c3–1f(d)(2)(ii); 17 CFR 240.15c3–1f(d)(3)(ii).

[184] *Better Markets Letter,* at 10, n.15.

[185] 17 CFR 240.15c3–1g.

[186] *Id.* Currently, each broker-dealer that uses the ANC computation has an ultimate holding company that has a principal regulator.

[187] *See Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26556–26557.

[188] *Id.*

[189] *Id.* at 26557.

[190] *See* paragraph (a)(3)(i)(F) of Rule 15c3–1g, as amended.

[191] *Id.*

[192] 17 CFR 240.15c3–3.

[193] *See* 15 U.S.C. 78aaa *et seq.*

[194] 17 CFR 240.15c3–3(b)(1).

[195] 17 CFR 240.15c3–3(c).

[196] 17 CFR 240.15c3–3(c).

[197] 17 CFR 240.15c3–3(d).

[198] 17 CFR 240.15c3–3(e).

[199] 17 CFR 240.15c3–3(e)(1).

[200] 17 CFR 240.15c3–3a.

[201] 17 CFR 240.15c3–3a.

[202] 17 CFR 240.15c3–3(e).

Accordingly, this requirement is intended to provide reasonable assurance that customer margin collateral deposited with a clearing agency or derivatives clearing organization related to security futures products will be available to be returned to the broker-dealer and, therefore, can serve as an appropriate offset to customer credits in the reserve formula.

The Commission proposed to remove the first criterion described above (*i.e.,* the highest investment-grade rating from an NRSRO).[203] The criteria are disjunctive and, therefore, a clearing agency or derivatives clearing organization needs to satisfy only one criterion to permit a broker-dealer to treat posted customer margin collateral as a reserve formula debit. In the proposing release, the Commission stated that the proposed amendment would not lessen the protections for customer funds and securities.[204] While one potential criterion would be removed, currently, only the Options Clearing Corporation (''OCC'') clears and accepts margin on security futures products. The OCC qualifies under two of the other criteria in Note G.[205] If at a later date another clearing entity accepts margin on security futures products, and it did not meet one of the remaining criteria, a broker-dealer may request an exemption for that clearing entity under Note G to Appendix A to Rule 15c3–3.[206] Thus, the proposed amendment does not disqualify any current clearing entities, nor require a broker-dealer to obtain new clearing memberships to comply with Rule 15c3–3.

The Commission received no comments on the proposed amendment to Rule 15c3–3. The Commission is adopting the amendment to Note G to Exhibit A to Rule 15c3–3 as proposed by removing paragraph (b)(1)(i).

2. Rule 10b–10

a. Proposal

Rule 10b–10 under the Exchange Act, the Commission's customer confirmation rule, generally requires broker-dealers effecting transactions for customers in securities, other than U.S. savings bonds or municipal securities, to provide those customers with a written notification, at or before completion of the securities transaction, disclosing certain information about the terms of the transaction.[207] This required disclosure includes, among other things, the date, time, identity, and number of securities bought or sold; the capacity in which the broker-dealer acted (*e.g.,* as agent or principal); yields on debt securities; and, under special circumstances, the amount of compensation the broker-dealer will receive from the customer and any other parties.[208] By requiring these disclosures, the rule serves a basic customer protection function by conveying information that: (1) Allows customers to verify the terms of their transactions; (2) alerts customers to potential conflicts of interest; (3) acts as a safeguard against fraud; and (4) allows customers a means of evaluating the costs of their transactions and the quality of the broker-dealer's execution.

The Commission proposed to delete paragraph (a)(8) from Rule 10b–10.[209] Paragraph (a)(8), which the Commission adopted in 1994, requires a broker-dealer to inform the customer in the confirmation if a debt security, other than a government security, is unrated by an NRSRO.[210] As explained when it was added to Rule 10b–10 in 1994, paragraph (a)(8) was intended to alert customers to the potential need to obtain more information about a security from a broker-dealer; it was not intended to suggest that an unrated security is inherently riskier than a rated security.[211]

The Commission had previously proposed, and re-proposed, the deletion of paragraph (a)(8) from Rule 10b–10.[212] These previous proposals, however, were prompted by concerns regarding the undue reliance on NRSRO ratings and confusion about the significance of those ratings. Because paragraph (a)(8) of Rule 10b–10 does not refer to NRSRO ratings as a means of determining creditworthiness, it arguably does not come strictly within section 939A. Nevertheless, to the extent that the provision may focus investor attention on ratings issued by NRSROs, as distinct from other items of information, the Commission believed deleting it would be consistent with the intent of the Dodd-Frank Act.

b. Comments

The Commission received four comments regarding the proposed removal of paragraph (a)(8) from Rule 10b–10. One commenter was supportive of the deletion, without providing any additional comment.[213] Another commenter recommended that in place of the deletion, the proposed rules should require Rule 10b–10 confirmations to include information that would ensure that investors understand the potential need to learn more about the debt securities that they have acquired from their broker-dealers.[214] The commenter recommended requiring broker-dealers to inform investors that debt securities vary in terms of their creditworthiness; that investors should understand the credit quality of the specific debt securities acquired through their broker-dealer; and that credit quality can affect not only the value of the debt securities, but also their liquidity and price stability.[215] In contrast, a third commenter believed that the removal of paragraph (a)(8) serves no useful purpose, stating: ''We do not see how requiring disclosure of the *absence* of a credit rating in any way encourages greater reliance on credit ratings.''[216] The commenter further recommended that if paragraph (a)(8) were deleted, the Commission should not replace it with

[203] *See Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26557.

[204] *Id.*

[205] At the end of 2012, OCC maintained $78.8 billion in margin deposits, well in excess of the $3 billion threshold set forth in paragraph (b)(1)(iii) of Note G. The OCC also maintained $2.7 billion in clearing member deposits, well in excess of the $500 million threshold set forth in paragraph (b)(1)(ii) of Note G. *See* OCC, *2012 Annual Report* (2012) (Notes 3 and 4 to the Financial Statements).

[206] The Commission may, in its sole discretion, grant such an exemption subject to such conditions as are appropriate under the circumstances if the Commission determines that such conditional or unconditional exemption is necessary or appropriate in the public interest and is consistent with the protection of investors. *See* 17 CFR 240.15c3–3a(b)(1)(iv), Note G.

[207] *See* 17 CFR 240.10b–10.

[208] *Id.*

[209] *See Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26563–26564 & n.80. Consistent with this proposed change, the Commission also proposed to re-designate paragraph (a)(9) of the rule, under which a broker-dealer that is not a member of the Securities Investor Protection Corporation generally must disclose that fact, as paragraph (a)(8). *Id.* at 26564 n.89, 26576.

[210] *See* 17 CFR 240.10b–10(a)(8); *Confirmation of Transactions,* Exchange Act Release No. 34962 (Nov. 10, 1994), 59 FR 59612, 59617 (Nov. 17, 1994), *corrected,* Securities Exchange Act Release No. 34962A (Nov. 18, 1994), 59 FR 60555 (Nov. 25, 1994).

[211] *Id.* (stating, ''In most cases, this disclosure should verify information that was disclosed to the investor prior to the transaction. If the customer was not previously informed of the security's unrated status, then confirmation disclosure may prompt a dialogue between the customer and the broker-dealer,'' and noting that the disclosure was ''not intended to suggest that an unrated security is inherently riskier than a rated security.'').

[212] *See References to Ratings of Nationally Recognized Statistical Rating Organizations,* 74 FR 52374; *References to Ratings of Nationally Recognized Statistical Rating Organizations,* 73 FR 40088.

[213] *See SIFMA Letter,* n.3 (''SIFMA endorses the Commission's proposed changes to Rules 15c3–3 and Rule 10b–10.'').

[214] *See Better Markets Letter.*

[215] *Id.*

[216] *See Sullivan & Cromwell Letter.*

any further required disclosures.[217] A fourth commenter recommended that paragraph (a)(8) of Rule 10b–10 should be retained.[218] The commenter stated that, given that the types of securities that are unrated by NRSROs typically include small offerings, the required broker-dealer disclosures may no longer signal to investors any need to investigate the quality of the securities being purchased.[219] The commenter added that the required notification that certain securities are unrated serves to encourage investors to evaluate the securities in which they are investing without undermining the overall intent to eliminate *reliance* upon ratings bestowed by NRSROs.[220]

c. Final Rule

After careful consideration of the received comments, the Commission has decided to delete paragraph (a)(8) from Rule 10b–10, as proposed. The Commission acknowledges that, to some extent, the paragraph may have served the purpose for which it was added to the rule in 1994 by prompting investors to investigate or question a broker-dealer about the quality of certain securities. Based on the comments received in response to the proposing release, however, the Commission believes it is likely that the paragraph's disclosure requirement has to a greater extent added to investors' undue reliance on credit ratings, and that the deletion of the paragraph is consistent with the intent of section 939A of the Dodd-Frank Act to reduce reliance on NRSRO credit ratings. In addition, requiring broker-dealers to use customer confirmations as a means of providing investors with general information related to credit risk and debt securities as suggested by commenters would not further paragraph (a)(8)'s purpose of flagging unrated securities for more careful investor scrutiny. The paragraph was added to the rule to require disclosure of information suggesting that investors may want to obtain more information about certain unrated securities, not to ''require that confirmations alert customers to the importance of understanding the credit quality of a debt security and the impact of credit quality on the value, resale, and price of such securities.'' [221] The purpose of Rule 10b–10 is not to educate investors about the characteristics of different kinds of securities in general, but rather, in the context of particular transactions, convey information allowing investors to verify the terms of their transactions, alert investors to potential conflicts of interest with their broker-dealers, deter and prevent deceptive and fraudulent acts and practices, and assist customers in evaluating the costs and quality of services proved by broker-dealers in connection with the execution of their securities transactions.[222]

The Commission further notes, as it did in the proposing release, that after the deletion of paragraph (a)(8), broker-dealers will not be prohibited from continuing to provide the information currently required by paragraph (a)(8) on a voluntary basis.[223] If broker-dealers believe that continuing to provide such information on confirmations would, for example, give investors an incentive to carry out additional research on their debt securities, the broker-dealers may continue to provide this disclosure at their discretion.[224] Also, in particular circumstances they may believe that a reasonable investor likely would consider a security's lack of a credit rating significant.

After consideration of the comments received, the Commission is removing paragraph (a)(8) and believes that it is unnecessary to replace the paragraph with any other disclosure requirement. Although the Commission recognizes the potential benefit of requiring broker-dealers to remind investors of the varying creditworthiness of debt securities, the Commission believes that such a requirement would be unnecessary given the other security-specific disclosures currently required by Rule 10b–10.[225] Also, general information about credit risk and other risks associated with corporate bonds is widely available to investors.[226]

III. Paperwork Reduction Act

Certain provisions of the amendments to the rules and form contain ''collection of information requirements'' within the meaning of the Paperwork Reduction Act of 1995 (''PRA'').[227] The Commission solicited comment on the estimated burden associated with the collection of information requirements in the proposed amendments. The Commission submitted the proposed collection of information requirements to the Office of Management and Budget (''OMB'') for review in accordance with 44 U.S.C. 3507 and 5 CFR 1320.11. The titles of the affected information collections are Rule 15c3–1 (OMB Control Number 3235–0200), Rule 15c3–3 (OMB Control Number 3235–0078), Rule 17a–4 (OMB Control Number 3235–0279), Rule 10b–10 (OMB Control Number 3235–0444), and the General Instructions to Form X–17A–5, Part IIB (OMB Control Number 3235–0498). An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information requirement unless it displays a currently valid OMB control number.

As discussed above, the Commission received eleven comment letters on the proposed amendments. Some of the comments in these letters relate indirectly to the PRA and are addressed below. The estimates contained in this section do not include any other possible costs or economic effects beyond the costs required for PRA purposes.[228]

A. Summary of Collection of Information

As discussed above, the Commission is adopting amendments to Rule 15c3–1, Appendices A, E, F, and G to Rule 15c3–1, Exhibit A to Rule 15c3–3, Rule 17a–4, the General Instructions to Form X–17A–5, Part IIB, and Rule 10b–10. These amendments are consistent with section 939A of the Dodd-Frank Act.

The amendments to Rule 15c3–1, and Rule 17a–4 establish a new standard of creditworthiness that will allow broker-dealers to establish their own policies and procedures to determine whether a security has only a minimal amount of credit risk. If a broker-dealer chooses to establish these policies and procedures, it would create a new ''collection of information'' burden for those broker-dealers, as explained below. The amendments to Appendices A, E, F, and G to Rule 15c3–1 and the General Instructions to Form X–17A–5, Part IIB remove provisions permitting reliance

[217] *Id.*

[218] *See CFA Institute Letter.*

[219] *Id.*

[220] *Id.*

[221] *See Better Markets Letter,* at 4.

[222] *See Confirmation of Transactions,* at 59 FR 59613; *Securities Confirmations,* Exchange Act Release No. 15219 (Oct. 4, 1978), 43 FR 47495, 47496 (Oct. 16, 1978).

[223] *See Removal of Certain References to Credit Ratings Under the Securities Exchange Act of 1934,* 76 FR at 26564. The Commission understands that, as a practical matter, broker-dealers will likely not reprogram their systems solely to remove the information even though the legal obligation to include it has been eliminated. Rather, it is anticipated that firms may choose to make the change at a later date as part of a larger reprogramming initiative.

[224] Based on a limited review of customer confirmations, the Commission understands that some broker-dealers currently disclose NRSRO ratings for rated securities even though this information is not required by paragraph (a)(8).

[225] *See* information broker-dealers must disclose as specified in paragraphs (a)(1) through (a)(7) of Rule 10b–10, as amended.

[226] *See, e.g.,* SEC's Office of Investor Education and Advocacy's Investor Bulletin, *What Are Corporate Bonds?* (June 2013), *available at http://www.sec.gov/investor/alerts/ib_corporatebonds.pdf.*

[227] 44 U.S.C. 3501 *et seq.*

[228] *See* discussion below in Section IV.D.

on NRSRO ratings to calculate haircuts and credit risk charges related to counterparties. In addition, the amendments to the Customer Protection Rule remove one method for verifying the status of a registered clearing agency or derivatives clearing organization under Note G to Exhibit A. Broker-dealers have to use a new method for verifying the status of a registered clearing agency or derivatives clearing organization may have to comply with a new ''collection of information'' within the meaning of the PRA.

The Commission does not believe that the amendment to Rule 10b–10, which eliminates a requirement that broker-dealers inform customers in transaction confirmations for debt securities (other than government securities) if a security is unrated by an NRSRO, would change the existing paperwork burden for Rule 10b–10.

B. Proposed Use of Information

The written policies and procedures required by the amendments to Rule 15c3–1, and the retention of these policies and procedures required by the amendment to Rule 17a–4, will assist Commission and SRO examination staff in evaluating whether the broker-dealer has a reasonable basis for determining if a security has only a minimal amount of credit risk. It also will assist examination staff and the broker-dealer in evaluating whether the broker-dealer has followed those policies and procedures when acquiring positions in commercial paper, nonconvertible debt, and preferred stock. In addition, written policies and procedures will provide a broker-dealer's personnel with consistent guidance on how to determine if a security has a minimal amount of credit risk for the purposes of complying with Rule 15c3–1.

The amendment to Rule 10b–10 will eliminate a requirement for transaction confirmations for debt securities (other than government securities) to inform customers if a security is unrated by an NRSRO. This amendment will alter neither the general requirement that broker-dealers generate transaction confirmations and send those confirmations to customers, nor the potential use of information contained in confirmations by the Commission, SROs, and other securities regulatory authorities in the course of examinations, investigations and enforcement proceedings.

C. Respondents

The Commission estimates that the collections of information would apply to the number of respondents as indicated in the following table.[229]

Rules	Number of broker-dealers
Amendments to Rule 15c3–1 (not including appendices) and Rule 17a–4	434
Amendments to Appendices A, E, F, and G to Rule 15c3–1	115
Amendments to Exhibit A to Rule 15c3–3	72
Amendments to the General Instructions to Form X–17A–5, Part IIB	4
Amendments to Rule 10b–10	502

D. Total Initial and Annual Reporting and Recordkeeping Burden

1. Rule 15c3–1 Appendices A, E, F, and G to Rule 15c3–1, Rule 17a–4, and the General Instructions to Form X–17A–5, Part IIB

The amendments to Rule 15c3–1 and Rule 17a–4 modify broker-dealers' existing practices to impose additional voluntary recordkeeping burdens. The amendments to Rule 15c3–1 replace NRSRO ratings-based criteria for evaluating creditworthiness with an option for a broker-dealer to apply a new standard based on the broker-dealer's own evaluation of creditworthiness. A broker-dealer that chooses not to make such an evaluation could instead take the higher haircuts as specified in Rule 15c3–1. A broker-dealer that chooses to evaluate the creditworthiness of securities will have to establish, document, maintain, and enforce policies and procedures that are reasonably designed to determine whether a security has a minimal amount of credit risk. Broker-dealers will be required to develop (if they have not already) criteria for assessing creditworthiness and apply those criteria to commercial paper, nonconvertible debt, and preferred stock included in their net capital calculations.

The Commission requested comment on the PRA burden associated with its proposed amendments to Rule 15c3–1 and Rule 17a–4. Two commenters discussed costs, although the comments did not explicitly address the PRA.[230] One commenter stated that ''[a] significant number of large broker-dealers have sophisticated internal credit review functions'' but those broker-dealers may not ''have access to internally generated analyses of all or nearly all issuers and securities.''[231] Both commenters were concerned that the costs imposed by the proposed amendments could be considerable, particularly for small and medium-sized broker-dealers.[232] One commenter noted, however, that ''the burden on small and medium-sized broker-dealers would be significantly reduced if the proposed amendment were to be interpreted . . . to permit policies and procedures that base the credit risk analysis solely on a small number of objectively determinable factors.''[233] The amended rule allows a broker-dealer to establish policies and procedures customized to its size and business activities.[234] For example, a smaller broker-dealer may decide to establish procedures that use a small number of objective factors or that default to the higher haircuts with respect to certain types of securities or money market instruments in lieu of establishing policies and procedures to address them. Both of these options should minimize the compliance burden on the broker-dealer. Furthermore, the Commission believes that many of the firms that hold commercial paper, nonconvertible debt securities, and preferred stock (or combinations thereof) have established policies and procedures for assessing creditworthiness; broker-dealers that have not established such policies and procedures do not typically hold large portfolios of these types of positions.[235] In addition, the broker-dealer should be able to use its policies and procedures to replicate its credit determinations and is not required to create and maintain records of those

[229] *See also* section IV.B., *infra.*

[230] *Bond Dealers Letter; SIFMA Letter.*

[231] *SIFMA Letter,* at 11, 18.

[232] *Bond Dealers Letter,* at 2; *SIFMA Letter,* at 18.

[233] *SIFMA Letter,* at 18.

[234] *See* section II.B.1.a.iii., *supra.*

[235] *SIFMA Letter,* at 18 (''A number of broker-dealers have access to credit analysis functions that could be applied to generate internal credit analysis of debt instruments.'').

determinations. Nonetheless, the Commission believes that those broker-dealers that already have policies and procedures in place for evaluating the overall risk and liquidity levels of proprietary securities for the purposes of Rule 15c3–1 may incur additional burdens as a result of the amendments. In particular, the policies and procedures may need to be modified to address the particular requirements of the amendments.

According to data collected by the Commission, of the approximately 4,462 broker-dealers registered with the Commission as of year-end 2012, approximately 434 broker-dealers maintained proprietary positions in debt securities and took haircuts on these securities pursuant to paragraphs (c)(2)(vi)(E), (c)(2)(vi)(F)(*1*), (c)(2)(vi)(F)(*2*) and (c)(2)(vi)(H) of Rule 15c3–1.[236] The Commission estimated in the proposing release that, on average, broker-dealers would spend 25 hours developing policies and procedures or revising their current policies and procedures for evaluating creditworthiness for purposes of the amendments to Rule 15c3–1.[237] The Commission received no comments on this estimate. The Commission believes that this estimate is still valid, resulting in an aggregate initial burden of 10,850 hours.[238] This estimate is based on the Commission's belief that many of these broker-dealers already have their own criteria in place for evaluating creditworthiness and, therefore, most broker-dealers will only be revising their current policies and procedures. If a broker-dealer does not have policies and procedures in place (*e.g.,* a small broker-dealer holding only a few debt securities) but determines to establish them rather than taking the larger haircut, the Commission believes that such a firm will likely establish less complex policies and procedures using a small number of objective factors.[239]

The Commission also estimated in the proposing release that, on average, each broker-dealer will spend an additional 10 hours a year reviewing and adjusting its own standards for evaluating creditworthiness for purposes of the amendments to Rule 15c3–1.[240] The Commission received no comments on this estimate and believes it is still valid. As a result, the Commission estimates that a broker-dealer will spend approximately twenty-five hours initially and ten hours on an annual basis on its policies and procedures. Thus, the industry, as a whole, is estimated to spend approximately 10,850 hours initially and 4,340 hours[241] annually reviewing and adjusting its standards for evaluating creditworthiness for purposes of the amendments to Rule 15c3–1.[242]

The Commission received no comments on the estimated burdens associated with the record retention requirements arising from the proposed amendments to Rule 17a–4. The Commission continues to believe that the requirement to retain the policies and procedures for three years pursuant to Rule 17a–4 would result in de minimis incremental costs beyond those already incurred under Rule 17a–4. The three-year preservation requirement in Rule 17a–4 will only be applicable once a broker-dealer changes its policies and procedures as the operative policies and procedures must be documented and maintained under the amendments to Rule 15c3–1. In addition, all broker-dealers are currently required to comply with the three-year preservation period in Rule 17a–4 for other records and should have procedures in place to satisfy such preservation requirements.

The amendments to the appendices to Rule 15c3–1 include amendments to certain recordkeeping and disclosure requirements that are subject to the PRA. The amendment to Appendix A to Rule 15c3–1 removes the NRSRO reference from the definition of the term *major market foreign currency.* However, the Commission does not intend to change which currencies would meet the definition of *major market foreign currency* because they will still have to have a substantial inter-bank foreign currency market. In the proposing release the Commission stated that there would be a recordkeeping burden if a broker-dealer wanted to request that a currency be deemed to meet the definition of *major market foreign currency,* by submitting such a request to the Commission. After further review, and based on staff experience with paragraph (c)(2)(vi) of Rule 15c3–1, the Commission believes that broker-dealers will rarely formally request in writing that a currency be added to the list. Thus, the Commission does not believe there is a burden associated with this amendment.[243]

The amendments to Appendices E and F to Rule 15c3–1 and conforming amendments to Appendix G would remove the provisions permitting reliance on NRSRO ratings for the purposes of determining counterparty risk. As a result of these deletions, an entity that wishes to use the approach set forth in these appendices to determine counterparty risks would need, as part of its initial application to use the alternative approach or in an amendment, to request Commission

[236] The number of 434 broker-dealers was obtained by reviewing broker-dealer Financial and Operational Combined Single (or ''FOCUS'') Reports for 2012 year-end and then calculating how many firms reported holding proprietary debt positions. For FOCUS Part II filers, the balances examined were ''Bankers Acceptances'' and ''Corporate Debt.'' For FOCUS CSE filers, the balances examined were: ''Money Market Instruments,'' ''Private Label Mortgage Backed Securities,'' ''Other Asset Backed Securities,'' and ''Corporate Debt.'' For Part IIA filers, the balance examined was ''Debt Securities.'' Broker-dealers that hold preferred stock also may hold positions in debt securities. However, because preferred stock is not a separate line item on the FOCUS Report, broker-dealers that hold only preferred stock and no other debt securities are not included in this estimate.

[237] *Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26568.

[238] 434 broker-dealers × 25 hours = 10,850 hours. It should be noted that this hour burden is less than the hour burden in the proposing release. This decrease is a result of the number of broker-dealers that reported holding proprietary debt positions on the FOCUS Report. The number decreased from 480 at 2009 year end to 434 at 2012 year end.

[239] *See SIFMA Letter,* at 18 (''the burden on small and medium-sized broker-dealers would be significantly reduced if the proposed amendment were to be interpreted . . . to permit policies and procedures that base the credit risk analysis solely on a small number of objectively determinable factors . . .'').

[240] *Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26568. Although the Commission has added language to the rule to clarify that a broker-dealer's policies and procedures must be reasonably designed to monitor its creditworthiness determination, the duty to monitor was required under the proposed rule and was reflected in the corresponding burden estimate. *See* section II.B.1.a.iii, *supra.*

[241] 434 broker-dealers × 10 hours = 4,340 hours.

[242] The Commission estimated in the proposing release that firms would use a controller to review these standards, both initially and on an annual basis. The Commission received no comments on this estimate. Thus, the Commission believes the per-firm costs of the controller to be approximately $10,475 initially and $4,190 on an annual basis, for an aggregate industry cost of $4,546,150 initially and $1,818,460 on an annual basis. For purposes of this analysis, the Commission is using salary data from the Securities Industry and Financial Markets Association (''SIFMA'') Report on Management and Professional Earnings in the Securities Industry 2012, which provides base salary and bonus information for middle management and professional positions within the securities industry, as modified by Commission staff to account for an 1800-hour work-year and multiplied by 5.35 to account for bonuses, firm size, employee benefits and overhead. Hereinafter, references to data derived from the report as modified in the manner described above will be cited as *SIFMA Report on Management and Professional Earnings in the Securities Industry 2012.* The Commission believes that the reviews required by the proposed amendments would be performed by the controller at an average rate $419 per hour. $419 × 25 = $10,475 × 434 = $4,546,150; $419 × 10 = $4,190 × 434 = $1,818,460.

[243] In the proposing release, the Commission estimated that submitting a request that a new currency met the definition of ''major market foreign currency'' would take 10 hours for a total burden to the industry of 1,580 hours. *See Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26568.

approval to determine credit charges based on internal credit ratings and make and keep current a record of the basis for the credit risk weight applied to each counterparty.

The Commission does not believe that the removal of the option permitting reliance on NRSRO ratings would affect the small number of entities that currently elect to compute their net capital deductions pursuant to the alternative methods set forth in Appendices E or F. Although the collections of information obligations imposed by the amendments are mandatory, applying for approval to use the alternative capital calculation is voluntary.[244] To date, a total of six entities are using the methods set forth in Appendix E, while four are using the methods set forth in Appendix F. All of the approved firms already use internal credit ratings to calculate market and credit risks under the alternative net capital calculation methods set forth in the appendices or are taking a 100% charge for counterparty risk. No firms are using NRSRO ratings to measure counterparty risk.[245] For each entity that already employs its own models to calculate market and credit risk and keeps current a record of the basis for the credit risk weight of each counterparty, the amendments would not alter the paperwork burden currently imposed by Appendices E and F. Firms that have Commission-approved models to calculate market and credit risk, but have chosen not to seek Commission approval to calculate counterparty risk during their initial applications, can file an amendment to their applications to calculate counterparty risk. Based on the staff's review of how firms approved to use Appendices E and F are calculating counterparty risk, the staff believes that of the firms that do not have models approved to calculate counterparty risk, none would use NRSRO ratings to calculate counterparty risk even if it remained an option. Instead, these firms would continue to take a 100% charge for counterparty risk or would amend their application if charges related to counterparty risk increased to the point that the 100% charge was no longer economically practical. Any PRA burdens from these amended applications are included in the PRA burden associated with Appendix E or Appendix F. Thus, the Commission does not believe there are any additional burdens associated with this rulemaking.

The staff estimates that three additional firms may apply for permission to use Appendix E and one additional firm may apply to use Appendix F. However, the Commission believes, and commenters did not contest, that there should be no additional paperwork burden on these firms based on the amendments. Any firm that applies to use Appendices E or F to Rule 15c3–1 must submit its internal models to the Commission for approval as part of that process. These models will calculate market risk and credit risk, including the counterparty charge, which is not a change from the previous approval process for a firm that is applying to use Appendix E or Appendix F. Thus, the Commission does not believe the amendments to Appendices E and F will alter the existing paperwork burden estimates for these collections.

The instructions to Form X–17A–5, Part IIB currently include a summary of the credit risk calculation in paragraph (d) of Rule 15c3–1f. Paragraph (d) of Rule 15c3–1f is amended to remove that part of the credit risk calculation that is summarized in Form X–17A–5, Part IIB. Accordingly, the Commission is adopting a conforming amendment to the form that would remove the summary of the credit risk calculation. The Commission received no comments on its estimate in the proposing release that there would be no change in the burden for the collection of information related to the instructions to Form X–17A–5, Part IIB in the proposing release. The summary in the instructions provides additional information for the benefit of the filer and is not related to the information reported on the forms. Accordingly, the Commission does not believe the amendment would result in a substantive revision to these collections of information.

2. Exhibit A to Rule 15c3–3

The amendment to Note G to Exhibit A to Rule 15c3–3 imposes additional recordkeeping burdens on certain broker-dealers that are mandatory. Note G allows a broker-dealer to include, as a debit in its customer reserve formula, the amount of customer margin related to customer positions in security futures products posted to a registered clearing or derivatives clearing organization that meets certain minimum standards that are indicia of long-term financial strength. Prior to this amendment, clearing organizations that maintained the highest investment grade rating from an NRSRO qualified under Note G.[246] The amendment removes this NRSRO criterion such that firms including the debit in their reserve formula calculations must rely on one of the remaining three non-NRSRO criterions, or seek an exemption from the Commission. Broker-dealers are expected to ensure that any clearing or derivatives clearing organization it posts margin to meets one of the criterions under Note G, which results in the creation and maintenance of records of those assessments. The Commission requested comment on all aspects of the burdens associated with Note G to Exhibit A to Rule 15c3–3 and received no comments. The Commission estimates that approximately 72 firms would be required to comply with the provisions of Note G as amended.[247] In the final release that added Note G to Exhibit A to Rule 15c3–3,[248] the Commission estimated that firms would each spend approximately 0.25 hours to verify that the clearing or derivatives clearing organizations they post customer margin to satisfy the conditions of Note G. In the proposing release for these rule amendments, the Commission again estimated that firms would spend approximately 0.25 hours to verify that a clearing or derivatives clearing organization satisfies the conditions of Note G. The Commission

[244] *See, e.g., Alternative Net Capital Requirements for Broker-Dealers That Are Part of Consolidated Supervised Entities,* Exchange Act Release No. 34–49830 (June 8, 2004), 69 FR 34428 at 34456 (June 21, 2004).

[245] In the proposing release, the Commission stated that all firms have models approved to calculate counterparty risk. Although the Commission received no comments on this estimate, upon further review the staff has determined that although no firm is using NRSRO ratings to calculate counterparty risk, not all firms have models approved to calculate counterparty risk (*i.e.,* some firms take the 100% charge).

[246] A broker-dealer may also include customer margin related to customers' positions in security futures products posted to a registered clearing or derivatives clearing organization: (1) That maintains security deposits from clearing members in connection with regulated options or futures transactions and assessment power over member firms that equal a combined total of at least $2 billion, at least $500 million of which must be in the form of security deposits; (2) that maintains at least $3 billion in margin deposits; or (3) which does not meet any of the other criteria but which the Commission has agreed, upon a written request from the broker-dealer, that the broker-dealer may utilize. 17 CFR 240.15c3–3a, Note G, (b)(1)(ii)–(iv).

[247] The number 72 comes from reviewing the members of the OCC listed in the member directory on the OCC's Web site, *available at http://www.optionsclearing.com/membership/member-information/*. Of the list of 228 members, the Commission looked only at those who trade in single stock futures. Of the list of members that trade in single stock futures, the Commission deleted any members who had the exact same firm name but different firm numbers. This methodology is consistent with the methodology used in the proposing release. *Removal of Certain References to Credit Ratings Under the Securities Exchange Act of 1934,* 76 FR at 26570 n.115. The Commission received no comments on this estimate.

[248] *See Reserve Requirements for Margin Related to Security Futures Products,* Exchange Act Release No. 34–50295 (Aug. 31, 2004), 69 FR 54182, 54188 (Sep. 7, 2004).

received no comments on this estimate and believes it is still valid. The Commission therefore estimates that broker-dealers that trade in single stock futures will spend a total of approximately 18 hours per year, initially and on an ongoing basis, to verify the status of a registered clearing or derivatives clearing organization imposed by this amendment.[249]

The Commission estimated in the proposing release that firms would spend one hour changing their methods of determining whether a clearing or derivatives clearing organization meets the remaining four requirements of Note G. The Commission received no comments on this estimate and believes it is still accurate. The result is an aggregate, one-time initial burden of 72 hours.[250]

3. Rule 10b–10

In the proposing release, the Commission stated that the proposed amendment to Rule 10b–10 was not expected to result in any significant change to the cost of providing confirmations to customers in connection with those transactions covered by paragraph (a)(8) of the rule.[251] The Commission did not receive any comments that addressed the Rule 10b–10 amendment's potential effects on the burden associated with generating and sending confirmations. The Commission continues to believe that broker-dealers need not incur any new costs if they choose not to input information that a debt security is unrated into their existing confirmation systems. Accordingly, the Commission continues to believe that the Rule 10b–10 amendment will not result in any significant change to the recordkeeping or reporting burdens of generating and sending confirmations, and retains this conclusion as originally proposed.

[249] 72 broker-dealers × .25 hours = 18 hours.

[250] 72 broker-dealers × 1 hour = 72 hours. The Commission notes that this hour burden is less than the hour burden in the proposing release. This decrease is a result of the number of OCC member firms that trade in single stock futures decreasing from 90 to 72. The Commission estimated in the proposing release that firms will use a senior operations manager to review these standards. The Commission received no comments on this estimate and believes that it is still accurate. The Commission therefore estimates that the one-time costs of a senior operations manager to be $341 per hour, resulting in an aggregate, one-time cost to the industry of $24,552. 72 broker-dealers × $341/hour × 1 hour = $24,552. *SIFMA Report on Management and Professional Earnings in the Securities Industry 2012.*

[251] *See Removal of Certain References to Credit Ratings Under the Securities Exchange Act of 1934,* 76 FR at 26575.

IV. Economic Analysis

A. Overview

The Commission is sensitive to the costs and benefits of its rules. When engaging in rulemaking that requires the Commission to consider or determine whether an action is necessary or appropriate in the public interest, section 3(f) of the Exchange Act requires that the Commission consider, in addition to the protection of investors, whether the action will promote efficiency, competition, and capital formation.[252] In addition, section 23(a)(2) of the Exchange Act requires that the Commission consider the effects on competition of any rules the Commission adopts under the Exchange Act, and prohibits the Commission from adopting any rule that would impose a burden on competition not necessary or appropriate in furtherance of the purposes of the Exchange Act.[253]

In the proposing release, the Commission solicited comment on the costs and benefits of the proposed amendments, including whether estimates of the costs and benefits were accurate and comprehensive.[254] The Commission further encouraged commenters to provide specific data and analysis in support of their views.[255] The Commission also requested comment on whether the proposed amendments would place a burden on competition, and promote efficiency, competition, and capital formation.[256]

The Commission received two comment letters addressing the Commission's estimates of the costs associated with the proposed amendments.[257] Generally, these commenters expressed concerns that the potential costs associated with the proposed rules could be considerable.[258] While commenters stated that the costs may be high, they did not provide quantified estimates of the costs—this reflects the fact that many of the costs and benefits of today's amendments are difficult to quantify with any degree of certainty, especially as practices at broker-dealers are expected to evolve and appropriately adapt to market developments. Moreover, this difficulty is aggravated by the fact that limited public data exists that is related to a broker-dealer's net capital calculation that could assist in quantifying certain costs. Consequently, the Commission has relied on qualitative assessments of the likely costs and benefits in its analysis. As discussed throughout this release, the Commission has modified the amendments being adopted today in a way that it believes will help to minimize costs to broker-dealers. A number of costs and benefits that are related to the rules being adopted today are discussed below.

As discussed above, the amendments to Rule 15c3–1, Appendices A, E, F, and G to Rule 15c3–1, Exhibit A to Rule 15c3–3, Rule 17a–4, the General Instructions to Form X–17A–5, Part IIB, and Rule 10b–10 implement section 939A of the Dodd-Frank Act by eliminating the reference to and requirement for the use of NRSRO ratings in these rules. The Commission recognizes that there are additional costs associated with adopting the amendments that are separate from the costs associated with the hour and cost burdens discussed in the PRA. The discussion below focuses on the Commission's reasons for adopting these amendments, the affected parties, the impact on efficiency, competition, and capital formation, and the costs and benefits of the amendments as compared to the baseline, described below, and to alternative courses of action.

B. Economic Baseline

The regulatory changes adopted today amend requirements that apply to broker-dealers registered with the Commission. However, security issuers, NRSROs, non-NRSRO credit rating agencies, and other providers of credit risk analysis as well as a broker-dealer's customers and counterparties could all be affected by the amendments. The discussion below characterizes the economic baseline against which the costs and benefits, as well as the impact on efficiency, competition, and capital formation, of today's amendments are measured. It includes the approximate numbers of broker-dealers that would be directly affected by today's amendments and a description of the relevant features of the economic and regulatory environment in which the various impacted parties operate. The economic baseline being used for this analysis is the economic and regulatory framework

[252] 15 U.S.C. 78c(f).

[253] 15 U.S.C. 78w(a)(2).

[254] An economic analysis was included in the proposing release. *See Removal of Certain References to Credit Ratings Under the Securities Exchange Act of 1934,* 76 FR at 26571–26574.

[255] *See Removal of Certain References to Credit Ratings Under the Securities Exchange Act of 1934,* 76 FR at 26574.

[256] *Id.*

[257] *See SIFMA Letter; Bond Dealers Letter.*

[258] *See Bond Dealers Letter,* at 2 (''the cost to comply may be prohibitively high for the smaller or middle-market broker-dealers''); *SIFMA Letter,* at 18 (''we believe the cost and complexity of developing a credit evaluation infrastructure covering many issuers and securities may be beyond the means of many broker-dealers'').

in existence just prior to the adoption of today's amendments.

The regulations that are affected by today's amendments include Rule 15c3–1, which provided prior to today's amendments, among other things, that a broker-dealer could apply a lesser capital charge (*e.g.,* less than the 15% catchall charge) for commercial paper, nonconvertible debt, and preferred stock if the instrument is rated in the higher rating categories by two NRSROs; the Appendices to Rule 15c3–1, which rely on credit ratings for calculating haircuts or credit risk charges related to counterparties; Exhibit A to Rule 15c3–3, which uses NRSRO ratings to determine whether a broker-dealer can include customer margin for transactions in securities futures products as a debit in its reserve formula; and Rule 10b–10, which requires disclosing in customer confirmations of securities transactions if non-government debt securities have not been rated by an NRSRO. The rule amendments would help to reduce any perceived Commission endorsement of NRSROs and NRSRO ratings and reduce reliance on credit ratings. The relevant rule amendments are described in detail below.

The broker-dealers registered with the Commission vary significantly in terms of their size, business activities, and the complexity of their operations. For example, carrying broker-dealers hold customer securities and funds.[259] Clearing broker-dealers clear transactions as members of securities exchanges, the Depository Trust & Clearing Corporation, and the OCC.[260] Many clearing broker-dealers are carrying broker-dealers, but some clearing broker-dealers clear only their own transactions and do not hold customer securities and cash.

A broker-dealer that claims an exemption from Rule 15c3–3 is generally referred to as ''non-carrying broker-dealer.'' Non-carrying broker-dealers include ''introducing brokers.'' [261] These non-carrying broker-dealers typically accept customer orders and introduce their customers to a carrying broker-dealer that will hold the customers' securities and cash along with the securities and cash of customers of other introducing broker-dealers and those of direct customers of the carrying broker-dealer. The carrying broker-dealer generally receives and executes orders of the introducing broker-dealer's customers.[262] Carrying broker-dealers generally also prepare trade confirmations, settle trades, and organize book entries of the securities.[263] Introducing broker-dealers also may use carrying broker-dealers to clear the firm's proprietary trades and carry the firm's securities. Another group of non-carrying broker-dealers effects transactions in securities such as mutual funds on a subscription-way basis.[264] Generally, customers purchase the securities by providing the funds directly to the issuer. Finally, some non-carrying broker-dealers act as finders by referring prospective purchasers of securities to issuers.[265]

The broker-dealer industry is the primary industry affected by the rule amendments, although the amendments impose different requirements on different types of broker-dealers. For example, only those broker-dealers that hold proprietary positions in commercial paper, nonconvertible debt, and preferred stock will be affected by the amendments to Rules 15c3–1 and 17a–4, only those broker-dealers that trade in foreign currency options will be affected by the amendments to Appendix A to Rule 15c3–1, and only those broker-dealers that clear and carry positions in security futures products for customers will be affected by the amendment to Exhibit A to Rule 15c3–3. The amendments to Appendices E and F to Rule 15c3–1 and the conforming amendments to Appendix G to Rule 15c3–1 and the General Instructions to Form X–17A–5, Part IIB will affect only ANC broker-dealers and OTC derivatives dealers. The amendment to Rule 10b–10 eliminates a disclosure requirement for broker-dealers that currently produce transaction confirmations for debt securities other than government securities.

To establish a baseline for competition among broker-dealers, the Commission looks at the status of the broker-dealer industry detailed below. In terms of size, the following tables illustrate the variance among broker-dealers with respect to total capital. The information in the tables is based on FOCUS Report data for calendar year 2012.

BROKER-DEALER CAPITAL AT CALENDAR YEAR-END 2012

[$ Millions]

Capital	Number of firms	Sum of total capital
Less than $500,000	2,347	$345

[259] Rule 15c3–1 specifies that a broker-dealer shall be deemed to carry customer or broker-dealer accounts ''if, in connection with its activities as a broker or dealer, it receives checks, drafts, or other evidences of indebtedness made payable to itself or persons other than the requisite registered broker or dealer carrying the account of a customer, escrow agent, issuer, underwriter, sponsor, or other distributor of securities'' or ''if it does not promptly forward or promptly deliver all of the securities of customers or of other brokers or dealers received by the firm in connection with its activities as a broker or dealer.'' 17 CFR 240.15c3–1(a)(2)(i); *see also* the description of Rule 15c3–1 in section II.B.1.a.i., *supra.* Further, Rule 15c3–3, defines the term *securities carried for the account of a customer* to mean ''securities received by or on behalf of a broker or dealer for the account of any customer and securities carried long by a broker or dealer for the account of any customer,'' as well as securities sold to, or bought for, a customer by a broker-dealer. 17 CFR 240.15c3–3(a)(2); *see also* the description of the Customer Protection Rule in section II.B.1.f., *supra.*

[260] *See Definitions of Terms and Exemptions Relating to the ''Broker'' Exceptions for Banks and Exemptions for Banks Under Section 3(a)(5) of the Securities Exchange Act of 1934,* Exchange Act Release No. 34–56501 (Sep. 24, 2007), 72 FR 56514 (Oct. 3, 2007), at n.269.

[261] *See Net Capital Rule,* Exchange Act Release No. 34–31511 (Nov. 24, 1992), 57 FR 56973 (Dec. 2, 1992) (describing the role of introducing broker-dealers).

[262] *Id.*

[263] *See, e.g.,* FINRA Rule 4311 (Carrying Agreements). This FINRA rule governs the requirements applicable to FINRA members when entering into agreements for the carrying of any customer accounts in which securities transactions can be effected. Historically, the purpose of this rule has been to require that certain functions and responsibilities are clearly allocated to either the introducing or carrying firm, consistent with the requirements of the SRO's and Commission's financial responsibility rules and other rules and regulations, as applicable. *See also Notice of Filing of Amendment No. 1 and Order Granting Accelerated Approval of a Proposed Rule Change Adopting, as Modified by Amendment No. 1, Rules Governing Guarantees, Carrying Agreements, Security Counts and Supervision of General Ledger Accounts in the Consolidated FINRA Rulebook,* Exchange Act Release 34–63999 (Mar. 7, 2011), 76 FR 12380 (Mar. 7, 2011).

[264] *See Books and Records Requirements for Brokers and Dealers Under the Securities Exchange Act of 1934,* Exchange Act Release No. 34–44992 (Oct. 26, 2001), 66 FR 55818 (Nov. 2, 2001) (''[T]he Commission recognizes that for some types of transactions, such as purchases of mutual funds or variable annuities, the customer may simply fill out an application or a subscription agreement that the broker-dealer then forwards directly to the issuer.'').

[265] *See* American Bar Association, *Report and Recommendations of the Task Force on Private Placement Broker-Dealers,* 23–24 (2005); *see also Net Capital Rule,* 57 FR 56973.

BROKER-DEALER CAPITAL AT CALENDAR YEAR-END 2012—Continued

[$ Millions]

Capital	Number of firms	Sum of total capital
Greater than or equal to 500,000 and less than 5 million	1,273	2,207
Greater than or equal to 5 million and less than 50 million	569	9,712
Greater than or equal to 50 million and less than 100 million	83	5,632
Greater than or equal to 100 million and less than 500 million	121	25,465
Greater than or equal to 500 million and less than 1 billion	27	19,688
Greater than or equal to 1 billion and less than 5 billion	26	56,034
Greater than or equal to 5 billion and less than 10 billion	7	47,922
Greater than or equal to 10 billion	9	185,022
Total	4,462	352,028

According to FOCUS Report data, as of December 31, 2012, there were approximately 4,462 broker-dealers registered with the Commission. Nine broker-dealers account for more than half of all capital held by broker-dealers. Of the 4,462 registered broker-dealers, 434 firms reported holding proprietary debt positions on their FOCUS Reports.[266] The Commission has also estimated that there are 101 broker-dealers that trade foreign currency options and are, therefore, subject to Appendix A to Rule 15c3–1.[267] Furthermore, there are six ANC broker-dealers (*i.e.,* firms that operate under Appendix E to Rule 15c3–1) and four OTC derivatives dealers (*i.e.,* firms that operate under Appendix F to Rule 15c3–1). In addition, the staff estimates that, for reasons unrelated to the rule amendments being adopted today, an additional three firms will apply to operate as ANC broker-dealers and one additional firm will apply to operate as an OTC derivatives dealer. The Commission also has estimated that there are 72 firms subject to Note G to Exhibit A to Rule 15c3–3.[268]

The Commission also believes other parties could be affected by today's amendments. Under the economic baseline, issuers of securities who obtain favorable ratings from two or more NRSROs enjoy the benefit of greater access to the capital markets because such securities are—holding other things constant—more attractive to broker-dealers who can take lower haircuts on such securities for the purposes of compliance with Rule 15c3–1. While the Commission does not intend the amendments to Rule 15c3–1 to alter the scope of securities and money market instruments that qualify for the lower haircuts, eliminating preferential regulatory treatment of NRSRO-rated securities could affect security issuers by altering the portfolio preferences of broker-dealers if, for example, broker-dealers establish policies and procedures for assessing creditworthiness that produce more conservative results than the NRSRO credit rating standard. These conservative results could cause broker-dealers to avoid holding positions that they would have held under the NRSRO credit rating standard. Alternatively, if the policies and procedures produce less conservative results, the amendments could alter the risk of broker-dealers' portfolios by causing them to hold positions that they would not have held when applying the NRSRO credit rating standard. Altering the risk of broker-dealers' portfolios could affect broker-dealers' customers, counterparties, and investors, all of whom are protected by Rule 15c3–1.

Finally, today's amendments could have a significant effect on the credit ratings industry. Currently there are ten NRSROs with the three largest accounting for the majority of all credit ratings.[269] The favorable regulatory treatment of NRSRO-rated securities increases demand for securities that have been favorably rated by at least two NRSROs. Eliminating this favorable treatment may alter incentives for broker-dealers to hold NRSRO-rated securities and may increase a broker-dealer's use of alternative providers of credit risk analysis, which could increase competition in the credit ratings industry.

1. Overview of Rule 15c3–1, Appendices A, E, F, and G to Rule 15c3–1, Exhibit A to Rule 15c3–3, the General Instructions to Form X–17A–5, Part IIB, and Rule 10b–10 Prior to Today's Amendments

a. Rule 15c3–1

As discussed above, Rule 15c3–1 prescribes minimum regulatory capital requirements for broker-dealers.[270] Rule 15c3–1 prescribes a ''net liquid assets test'' designed to require a broker-dealer to maintain at all times more than one dollar of highly liquid assets for each dollar of liabilities (*e.g.,* money owed to customers and counterparties), excluding liabilities subordinated by contract to all other creditors. Under the economic baseline, Rule 15c3–1 prescribed a lower haircut to certain types of debt instruments held by a broker-dealer if the securities were rated in higher rating categories by at least two NRSROs, since those securities typically are less volatile in price than securities that are rated in the lower categories or are unrated. Specifically, to receive the benefit of a reduced haircut on commercial paper, the commercial paper had to be rated in one of the three highest rating categories by at least two NRSROs;[271] to receive the benefit of a reduced haircut on a nonconvertible debt security and preferred stock, the security had to be

[266] *See* section III.C., *supra.*

[267] To arrive at this number, the Commission reviewed the members of the OCC listed in the member directory on the OCC's Web site *available at http://www.optionsclearing.com/membership/member-information/.* Of the list of 228 members, the Commission looked only at those that trade in index options because members approved to trade index options are also approved to trade such foreign currency options. Of the list of members that trade in index options, the Commission deleted any members that had the exact same firm name but different firm numbers. The Commission received no comments on its estimate of the number of broker-dealers that would be affected by the amendment to Appendix A to Rule 15c3–1 in the proposing release. *See also Removal of Certain References to Credit Ratings under the Securities Exchange Act of 1934,* 76 FR at 26568.

[268] *See* section III.C., *supra.*

[269] *See* Commission, *Annual Report on Nationally Recognized Statistical Rating Organizations* (December 2012) (estimating that as of December 2011, the three largest NRSROs accounted for approximately 96% of all outstanding credit ratings); Commission, *Report to Congress on Assigned Credit Ratings* (December 2012) (estimating that as of December 2011, the three largest credit rating agencies accounted for approximately 91% of structured product ratings).

[270] *See* 17 CFR 240.15c3–1; *see also* discussion in section II.B.1.a.i., *supra.*

[271] 17 CFR 240.15c3–1(c)(2)(vi)(E).

rated in one of the four highest rating categories by at least two NRSROs.[272] If securities were not eligible for the reduced haircut, they were subject to a greater haircut (*e.g.,* 15%), provided they had a ready market. The 15% haircut is derived from the catchall haircut amount that applies to a security not specifically identified in Rule 15c3–1 as having an asset-class specific haircut, provided the security is otherwise deemed to have a ready market, among other requirements. Securities without a ready market are subject to a 100% haircut.

b. Appendix A to Rule 15c3–1

Appendix A to Rule 15c3–1 permits broker-dealers to employ a standardized theoretical option pricing model to determine a potential loss for a portfolio of listed options positions and related positions to compute a single haircut for the group of positions.[273] Under Appendix A, a broker-dealer groups the options and related positions in a portfolio and stresses the current market price for each position at ten equidistant points along a range of positive and negative potential future market movements, using an approved theoretical option pricing model that satisfies certain conditions specified in the rule.[274] Positions that have more potential price volatility must be stressed across a wider range of positive and negative potential future market movements than positions with lower price volatility.[275] For example, a broker-dealer other than a non-clearing option specialist or market maker must employ a range of potential future market movements for major market foreign currencies of (±) 6%, whereas the range for all other foreign currencies is (±) 20%.[276] Thus, major market foreign currency options receive more favorable treatment than options on all other currencies when using theoretical option pricing models to compute net capital deductions.[277] Under the economic baseline, the rule defined the term *major market foreign currency* to mean ''the currency of a sovereign nation whose short term debt is rated in one of the two highest categories by at least two nationally recognized statistical rating organizations and for which there is a substantial inter-bank forward currency market.''

c. Appendix E to Rule 15c3–1

Under Appendix E to Rule 15c3–1, ANC broker-dealers are permitted to add back to net worth uncollateralized receivables from counterparties arising from OTC derivatives transactions (*i.e.,* they can add back the amount of the uncollateralized current exposure).[278] Instead of the 100% deduction that applies to most unsecured receivables under Rule 15c3–1, ANC broker-dealers are permitted to take a credit risk charge based on the uncollateralized credit exposure to the counterparty.[279] The credit risk charge is derived, in part, by using an applicable credit risk weight factor.[280] Appendix E to Rule 15c3–1 prescribes three standardized credit risk weight factors (20%, 50%, and 150%) and, as an alternative, permits an ANC broker-dealer with Commission approval to use internal methodologies to determine appropriate credit risk weights to apply to counterparties.[281] Under the economic baseline, ANC broker-dealers were permitted to use NRSRO credit ratings or internally derived credit ratings to determine the appropriate credit risk weight factor.

d. Appendix F to Rule 15c3–1 and Form X–17A–5, Part IIB

Under Appendix F to Rule 15c3–1, OTC derivatives dealers are required to deduct from their net capital credit risk charges that take counterparty risk into consideration.[282] As part of this deduction, the OTC derivatives dealer must apply a counterparty risk weight factor of either 20%, 50%, or 100%.[283] In addition, OTC derivatives dealers must take a concentration charge where the net replacement value in the account of any one counterparty exceeds 25% of the OTC derivatives dealer's tentative net capital.[284] Under the economic baseline, the counterparty risk weight factor (*i.e.,* 20%, 50%, or 100%) was determined using either NRSRO credit ratings or the firm's internal credit ratings.[285] The concentration charge also was determined using either NRSRO credit ratings or the firm's internal credit ratings.

e. Appendix G to Rule 15c3–1

Appendix G to Rule 15c3–1 provides that broker-dealers may use the ANC computation only if their ultimate holding companies agree to provide the Commission with additional information about the financial condition of the holding company and its affiliates.[286] Paragraph (a) of Appendix G sets forth a methodology for computing allowable capital and allowances for market and credit risk at the consolidated holding company level. Under the economic baseline, one aspect of calculating credit risk in Appendix G provided that those firms must use credit ratings in accordance with the applicable provisions of Appendix E.

f. Exhibit A to Rule 15c3–3

Rule 15c3–3 is designed to protect customer funds and securities held by broker-dealers.[287] In general, Rule 15c3–3 requires a broker-dealer to take two steps. First, a broker-dealer must maintain possession or control of all fully paid and excess margin securities of its customers. In this regard, a broker-dealer must make a daily determination in order to comply with this aspect of the rule. Second, the broker-dealer must make a periodic computation to determine how much money it is holding that is either customer money or money obtained from the use of customer securities (''credits''). From that figure, the broker-dealer subtracts the amount of money that it is owed by customers relating to customer transactions (''debits''). If the credits exceed the debits after this ''reserve formula'' computation, the broker-dealer must deposit the excess in a customer reserve account. If the debits exceed credits, no deposit is necessary. Funds deposited in a customer reserve account cannot be withdrawn until the broker-dealer completes another computation that shows that the firm has on deposit more funds than the reserve formula requires.

Exhibit A to Rule 15c3–3 prescribes the formula that a broker-dealer must use to determine its reserve requirement. Under the economic baseline, Note G to Exhibit A provided that a broker-dealer could include margin required for customer transactions in security futures products as a debit in its reserve formula computation if that margin is on deposit

[272] 17 CFR 240.15c3–1(c)(2)(vi)(F)(*1*), (c)(2)(vi)(F)(*2*) and (c)(2)(vi)(H).

[273] *See* 17 CFR 240.15c3–1a(b)(1); *see also* discussion in section II.B.1.b.i., *supra.*

[274] *See* 17 CFR 240.15c3–1a(b)(1).

[275] *See* 17 CFR 240.15c3–1a(b)(1)(iii).

[276] *See* 17 CFR 240.15c3–1a(b)(1)(iii)(B) through (C).

[277] *See* 17 CFR 240.15c3–1a(b)(1)(iii)(B) through (C) and (b)(1)(iv)(A).

[278] *See* 17 CFR 240.15c3–1e(c); *see also* discussion in section II.B.1.c.i., *supra.*

[279] *See* 17 CFR 240.15c3–1e(c); 17 CFR 240.15c3–1(a)(7).

[280] *See* 17 CFR 240.15c3–1e(c)(1)(ii).

[281] *See* 17 CFR 240.15c3–1e(c)(4)(vi).

[282] *See* 17 CFR 240.15c3–1f(d); *see also* discussion in section II.B.1.d.i., *supra.*

[283] *See* 17 CFR 240.15c3–1f(d)(2).

[284] *See* 17 CFR 240.15c3–1f(d)(3).

[285] *See* 17 CFR 240.15c3–1f(d)(2) and (4); *see also* discussion in section II.B.1.d.i., *supra.*

[286] 17 CFR 240.15c3–1g.

[287] *See* 17 CFR 240.15c3–3; *see also* discussion in section II.B.1.f., *supra.*

at a clearing agency or derivatives clearing organization that: (1) Maintains the highest investment-grade rating from an NRSRO; (2) maintains security deposits from clearing members in connection with regulated options or futures transactions and assessment power over member firms that equal a combined total of at least $2 billion, at least $500 million of which must be in the form of security deposits; (3) maintains at least $3 billion in margin deposits; or (4) obtains an exemption from the Commission.[288]

g. Rule 10b–10

Rule 10b–10, the Commission's customer confirmation rule, generally requires broker-dealers effecting transactions for customers in securities, other than U.S. savings bonds or municipal securities, to provide those customers with a written notification, at or before completion of the securities transaction, disclosing certain information about the terms of the transaction.[289] This required disclosure includes the date, time, identity, and number of securities bought or sold; the capacity in which the broker-dealer acted (*e.g.,* as agent or principal); yields on debt securities; and, in some circumstances, the amount of compensation the broker-dealer will receive from the customer and any other parties. By requiring these disclosures, the rule serves a basic customer protection function by conveying information that: (1) Allows customers to verify the terms of their transactions; (2) alerts customers to potential conflicts of interest; (3) acts as a safeguard against fraud; and (4) allows customers a means of evaluating the costs of their transactions and the quality of the broker-dealer's execution. Under the economic baseline, Rule 10b-10 required a broker-dealer to inform the customer in the confirmation if a debt security, other than a government security, is unrated by an NRSRO.

C. Effect on Efficiency, Competition, and Capital Formation

The amendments adopted today have the potential to affect competition, efficiency, and capital formation. This section discusses what the Commission believes to be potential effects across three groups of market participants: (1) Broker-dealers, (2) security issuers, and (3) issuers of credit ratings.[290]

1. Effects on the Broker-Dealer Industry

Under the economic baseline, all broker-dealers employ a uniform standard—an NRSRO credit rating—to determine whether a position in commercial paper, nonconvertible debt, or preferred stock is entitled to a lower haircut for purposes of Rule 15c3–1. Today's amendments eliminate this uniform standard and require that broker-dealers develop internal policies and procedures for determining whether these types of positions have only a minimal amount of credit risk and, therefore, are entitled to the lower haircut. As one commenter noted, ''the cost and complexity of developing a credit evaluation infrastructure covering many issuers and securities may be beyond the means of many broker-dealers.'' [291] Also, as the FOCUS Report data for calendar year 2012 makes clear, the majority of broker-dealers are small (with capital less than $500,000).[292] As noted by several commenters, any new regulatory requirement with significant fixed costs has the potential to disadvantage small and medium-sized broker-dealers.[293] Such disadvantages could result in increased concentration in the broker-dealer industry.

However, the Commission does not intend or expect broker-dealers to individually duplicate the function of credit rating agencies. To do so would require broker-dealers, particularly small and medium sized broker-dealers, to incur significant expense, potentially reducing competition in the broker-dealer industry and harming economic efficiency through duplication of effort.[294] Instead, the Commission expects that today's amendments will create opportunities for NRSROs, non-NRSRO credit rating agencies, and other providers of credit risk analysis to offer products and services that facilitate compliance with today's amendments. Although broker-dealers with large portfolios of debt securities and well-developed credit analysis capabilities may prefer to use an internal credit risk function for assessing creditworthiness, it will not be cost effective or practical for other broker-dealers to support an internal credit risk department comprised of analysts who perform internal credit assessments. These broker-dealers may instead establish a process for assessing creditworthiness that relies more on external factors, such as external credit assessments and market data, and that process will be evaluated for reasonableness in light of the firm's circumstances (*e.g.,* the size of the broker-dealer and the types and sizes of the positions typically held by the broker-dealer). The Commission also anticipates that some broker-dealers, particularly those with minimal proprietary positions in commercial paper, nonconvertible debt, and preferred stock, will choose to devote no resources toward credit risk analysis and to maintenance of policies and procedures, and instead will apply a greater haircut to their proprietary positions as permitted by the rule.[295]

Based on these considerations, the Commission does not believe that the burden of complying with today's amendments will result in significant changes to the competitive structure of the broker-dealer industry in general, nor to the small subset of broker-dealers with positions in commercial paper, nonconvertible debt, and preferred stock that are directly affected by today's amendments.

In addition to the aforementioned potential direct effects on efficiency and competition, today's amendments may affect economic efficiency indirectly by altering the net capital levels in the broker-dealer industry. A broker-dealer that elects to take a higher haircut rather than make a credit risk determination or one that overestimates the credit risk in its position will reserve more net capital than is required by Rule 15c3–1. This could affect the broker-dealer's ability to hold (or add to) its positions. Conversely, some broker-dealers may underestimate the credit risk of their positions. Indeed, broker-dealers have an incentive to underestimate credit risk in order to apply the lower capital charge. Such a determination could have a potential impact on the firm's ability, if it experiences financial difficulties, to be in a position to meet its obligations to customers, investors, and other counterparties and generate resources to wind-down its operations in an orderly manner without the need of a formal liquidation proceeding, with attendant costs. Increasing discretion in assessing creditworthiness for purposes of Rule 15c3–1 can facilitate such underestimation of credit risk. The Commission believes that this represents a significant risk in today's amendments. Broker-dealers whose internal evaluations typically are inconsistent with market data likely will

[288] 17 CFR 240.15c3–3a, Note G.

[289] 17 CFR 240.10b–10; *see also* discussion in section II.B.2.a., *supra.*

[290] Although this section IV.C. of the release focuses on these three groups of market participants whose businesses may be more directly impacted by the final rules, the impacts on other participants are discussed elsewhere in the release. *See, e.g.,* section IV.D., *infra.*

[291] *SIFMA Letter,* at 18.

[292] *See* section IV.B., *supra.*

[293] *SIFMA Letter,* at 11; *Bond Dealers Letter,* at 2.

[294] *See generally SIFMA Letter,* at 11.

[295] Although this approach would decrease the firm's direct cost of complying with the rule amendments, it would increase the amount of capital the broker-dealer is required to maintain to comply with Rule 15c3–1, increasing the indirect compliance costs.

need to spend more time addressing examiners' concerns regarding the reasonableness of their policies and procedures and the accuracy of their determinations that a security or money market instrument has only a minimal amount of credit risk; a broker-dealer's desire to avoid these costs may help mitigate the broker-dealers' incentives to underestimate credit risk.

2. Effects on Security Issuers

Today's amendments could impact capital formation by altering the set of securities that qualify for preferential treatment under Rule 15c3–1. Under the economic baseline, issuers of commercial paper, nonconvertible debt securities, and preferred stock who obtain favorable ratings from two or more NRSROs benefit from having lower haircuts apply to their issuances. Consequently, these issuers may have greater access to the capital markets, while issuers without such a rating may have more limited access. The regulatory preference for NRSRO-rated securities also benefits issuers who can afford to have their securities rated by NRSROs, and discourages broker-dealers from considering all the relevant credit risk factors when making portfolio decisions. By eliminating the regulatory preference for NRSRO-rated securities, today's amendments could alter the set of securities qualifying for lower net capital charges, which would affect broker-dealers' portfolio preferences. For example, the amendments could increase access to capital markets for smaller issuers whose commercial paper, nonconvertible debt securities, or preferred stock have only a minimal amount of credit risk, but for whom the costs of obtaining an NRSRO rating is potentially prohibitive. Such changes could increase competition among issuers for capital and improve the efficiency of the capital allocation process.

While it is the intent of the Commission that today's amendments not alter the quality of assets that qualify for the lower haircut, it is nonetheless a possibility that the policies and procedures that broker-dealers establish will change the risk and/or net capital levels of broker-dealers. Changes or perceived changes to the amount of net capital being held by a broker-dealer could have negative repercussions on confidence in broker-dealers' financial position among their customers, counterparties, and investors. These impacts on confidence could disrupt the orderly functioning of the markets—for example, by encouraging counterparties to reduce their exposures to broker-dealers in response to uncertainty about broker-dealers' financial positions—and thereby harm the capital formation process.

3. Effects on the Credit Ratings Industry

Finally, today's amendments could have an effect on competition in the credit rating agency industry with consequences on economic efficiency. Currently there are ten NRSROs with the three largest accounting for the majority of all credit ratings. As noted earlier, the favorable regulatory treatment of NRSRO-rated securities increases demand for securities that have been rated by at least two NRSROs. Eliminating this favorable treatment may increase broker-dealers' use of alternative providers of credit risk analysis, which could increase competition in the credit rating agency industry. Furthermore, to the extent that NRSRO ratings are biased, as some have argued, additional competition among credit rating providers could help expose any such biases and increase incentives for NRSROs to produce accurate ratings.

Reducing the emphasis on NRSRO ratings also could adversely affect the quality of NRSRO ratings. Currently, the importance attached to NRSRO ratings may impart franchise value to the NRSRO's ratings business. Eliminating references to NRSRO ratings in certain federal regulations could reduce these franchise values and mitigate NRSROs' incentives to produce credible and reliable ratings. Moreover, the Commission recognizes that the elimination of the required use of credit ratings in the specified Commission rules and forms may reduce the incentive for credit rating agencies to register as NRSROs with the Commission and thereby be subject to the Commission's oversight and the statutory and regulatory requirements applicable to NRSROs. To the extent that the quality and accuracy of NRSRO ratings is adversely affected, negative impacts on the capital allocation process and economic efficiency could result.

D. Costs and Benefits of the Rule Amendments

1. Rule 15c3–1 and Rule 17a–4

a. Benefits

The Commission requested comment on all aspects of the benefits associated with the amendments to Rule 15c3–1, the appendices to Rule 15c3–1, and Rule 17a–4, and received no comments. The Commission believes that one of the primary benefits of the amendments being adopted today is reducing potential undue reliance on NRSRO ratings that could be caused by references to NRSROs in Commission rules. Significantly, the Commission believes that eliminating references to NRSRO ratings in its rules would remove any appearance that the Commission has placed its imprimatur on such ratings. The Commission, however, also recognizes that credit ratings provide useful information to institutional and retail investors as part of the process of making an investment decision.

The Commission believes that the amendments to Rule 15c3–1 and its appendices, as well as the conforming amendment to Rule 17a–4, will encourage a more complete assessment of the credit risks associated with securities held by broker-dealers. As the NRSROs themselves have stressed, NRSRO ratings are a one-dimensional measure that summarizes the likelihood that an obligor or financial obligation will fail to repay investors in accordance with the terms on which they made their investment and investors' expected recoveries in the event of such a failure.[296] The simplicity of a one-dimensional measure is both its major advantage and its main limitation. For comparing securities with similar risk profiles, one-dimensional credit ratings are a useful summary measure. However, for securities with different risk profiles, such ratings can obscure important information about underlying differences in risk, such as time effects, default correlations, and the shape of loss distributions. The Commission expects that the amendments adopted today will encourage broker-dealers to incorporate this additional information in their credit risk evaluation process.

Many broker-dealers already conduct their own risk evaluation. As one commenter noted "[a] significant number of large broker-dealers have sophisticated internal credit review functions." [297] However, for those broker-dealers that do not currently have their own means of evaluating risk for purposes of the amendments to Rule 15c3–1, the approach being adopted today will allow them to incorporate various observable factors and external

[296] *See, e.g.,* Fitch, *Inside the Ratings: What Credit Ratings Mean,* (Aug. 2007), at 1; Testimony of Michael Kanef, Group Managing Director, Moody's Investors Service, Before the United States Senate Committee on Banking, Housing, and Urban Affairs (Sep. 26, 2007), at 2; Testimony of Vickie A. Tillman, Executive Vice President, Standard & Poor's Credit Market Services, Before the United States Senate Committee on Banking, Housing, and Urban Affairs (Sep. 26, 2007), at 3.

[297] *SIFMA Letter,* at 11.

information sources in their new risk evaluation processes, which will lead to a better understanding of the risks associated with those securities.

b. Costs

The Commission recognizes, as a result of today's amendments, that broker-dealers may incur additional costs associated with performing a more detailed and comprehensive analysis of the debt securities they own. The Commission received two comments on the costs associated with the proposed amendments to Rule 15c3–1.[298] As stated above, one commenter noted that ''the cost and complexity of developing a credit evaluation infrastructure covering many issuers and securities may be beyond the means of many broker-dealers.'' [299] Another commenter worried that ''the cost to comply may be prohibitively high for the smaller or middle-market broker-dealers.'' [300] As has been noted above, the Commission does not intend or expect broker-dealers to individually duplicate the function of credit rating agencies. Thus, the Commission believes that the costs of compliance with the amendments to Rule 15c3–1 and its appendices, as well as the conforming amendment to Rule 17a–4, would be minimal for the ''significant number of large broker-dealers'' that have a ''sophisticated internal credit review function'' for net capital purposes.[301] Of the approximately 434 broker-dealers that hold proprietary debt positions, the Commission recognizes that the level of sophistication varies widely. The broker-dealers with less sophisticated internal procedures for analyzing credit risk may incur costs to establish and develop procedures that would be used to assess financial instruments for the purposes of determining whether the lower haircuts could appropriately be applied. However, the Commission believes that because the determination of a minimal amount of credit risk will vary among firms, and because broker-dealers may create policies and procedures using a small number of objective factors and external assessments, firms will be able to keep costs lower than if they were mandated to create policies and procedures based on numerous specified factors.[302]

There will be minimal costs associated with the amendments for firms that use Appendix A to Rule 15c3–1. The amendment to the definition of *major market foreign currency* is not intended to change the foreign currencies that currently receive lower haircuts under the rule. Therefore, the Commission does not believe there will be any costs associated with the amendments.

Firms that use Appendices E and F to Rule 15c3–1 already undergo an approval process to use internal credit ratings to determine credit risk charges for each counterparty. Any new firms that apply to use either Appendix E or Appendix F will not incur any separate costs as a result of the amendments. Currently, firms that apply to use these appendices must have their internal models approved by the Commission prior to using their selected appendix. Although the Commission will have to assess the firm's process for determining internal credit ratings, this step will not cause broker-dealers who are applying to use these appendices to incur any additional costs. Furthermore, because the firms currently using these appendices have traditionally used models to compute capital charges, as opposed to NRSRO ratings, these firms will not incur any additional costs by complying with the amendments.

2. Exhibit A to Rule 15c3–3

a. Benefits

The Commission requested comment on all aspects of the benefits associated with the amendment to Exhibit A to Rule 15c3–3 and received no comments. The amendment eliminates a criterion that qualified the debits at a clearing agency or derivatives clearing organization if it was assigned the highest credit rating given by any NRSRO. Broker-dealers instead will be required to look to two other criterions based on financial metrics.

b. Costs

The Commission requested comment on all aspects of the costs associated with Note G to Exhibit A to Rule 15c3–3 and received no comments. The total cost of compliance with Note G to Exhibit A to Rule 15c3–3 will be minimal as the removal of the NRSRO credit ratings criterion from Note G is neither intended nor expected to change current security futures margining practices by broker-dealers. As stated in the PRA section, the Commission anticipates that a broker-dealer will incur a one-time cost to verify that a clearing or derivatives clearing organization meets the requirements of Note G. If a broker-dealer is currently using one of the non-NRSRO criterions, it will not incur any one-time costs.

3. Rule 10b–10

a. Benefits

The Commission believes that the amendment to Rule 10b–10 will benefit investors. As explained previously, the existing requirement to inform customers if a debt security, other than a government security, is unrated by an NRSRO may have the unintended effect of suggesting that rated securities are inherently better or less risky than unrated debt securities. The Commission believes that the existence of a rating should not give an investor extra comfort regarding the risks associated with the rated security. The amendment, by removing paragraph (a)(8)'s requirement to disclose whether certain securities are rated by an NRSRO, should help avoid promoting excessive reliance on NRSRO ratings. It also should help encourage investors to view NRSRO ratings as only one of multiple types of information relevant to evaluating credit risk. This in turn should help investors make more informed decisions regarding investments in debt securities.

b. Costs

As stated in the proposing release, the Commission does not expect the amendment to result in any significant changes in the costs associated with Rule 10b–10. Broker-dealers will continue to generate transaction confirmations and send those confirmations to customers, and the amendment is not expected to change the cost of generating and sending confirmations. Moreover, the Commission believes that broker-dealers may not incur costs if they choose not to input information that a debt security is unrated into their existing confirmation systems.

As stated above, the Commission acknowledges that, in some instances, eliminating paragraph (a)(8) of Rule 10b–10 may remove some incentive to investigate the quality of unrated debt securities. The Commission believes, however, that any such potential cost would be balanced by the benefit of encouraging investors not to rely excessively on credit ratings for information about credit risk and to consider additional information.

[298] *Bond Dealers Letter,* at 2; *SIFMA Letter,* at 11, 18.

[299] *SIFMA Letter,* at 18.

[300] *Bond Dealers Letter,* at 2.

[301] *SIFMA Letter,* at 11.

[302] *See SIFMA Letter,* at 18 (''we believe the burden on small and medium-sized broker-dealers would be significantly reduced if the proposed amendment were to be interpreted . . . to permit policies and procedures that base the credit risk analysis solely on a small number of objectively determinable factors . . .'').

E. Alternatives

1. Rule 15c3–1 and Rule 17a–4

In adopting the amendments to Rule 15c3–1, the Commission considered several alternative approaches, including suggestions by commenters. The main suggestion by commenters was to use an objective standard of creditworthiness instead of a subjective standard of creditworthiness.[303] Specifically, one commenter suggested the use of credit spreads and/or inclusion on an index as an objective standard.[304] Although the Commission considered these standards, it determined the alternatives would not be practical because not all bonds are included on an index and for bonds that are thinly traded the yield spreads could include liquidity premia that have little relation to the credit risk of the bond, reducing the usefulness of the yield spreads as a signal for credit risk. Furthermore, creating different standards of creditworthiness for different securities could increase costs for broker-dealers that hold multiple types of securities. The Commission does, however, believe that objective factors could play an important role in determining whether a security or money market instrument has a minimal amount of credit risk. To emphasize this point, the Commission added language to paragraph (c)(2)(vi)(I) that was not in the proposed rule text that states that policies and procedures that are reasonably designed ''should result in assessments of creditworthiness that typically are consistent with market data.'' This language should encourage broker-dealers to review at least one external factor, such as credit spreads or pricing, when making its credit risk determination. In addition, assessments that are consistent with market data should take some of the subjectivity away from each broker-dealer when making a credit risk determination. Rather than mandate a specific set of factors that broker-dealers must use when assessing credit risk, the Commission thought it was better to allow broker-dealers to determine what specific factors would work best for their specific circumstances.

The Commission understands that by not mandating an objective standard to determine the creditworthiness of a security or money market instrument there is a risk that a broker-dealer may incorrectly assess the credit risk. Using a subjective standard also could lead to inconsistent determinations of credit risk of the same security or money market instrument among broker-dealers. Inconsistent determinations of credit risk will lead to situations where broker-dealers that determine the security has only a minimal amount of credit risk will apply a lower haircut to the position than broker-dealers that determine that the security does not have a minimal amount of credit risk. The Commission expects, however, that the risk of this occurring will be mitigated by the Commission and SRO examination process, during which Commission and SRO examiners will assess the reasonableness of broker-dealers' policies and procedures for determining net capital haircuts under the minimal amount of credit risk standard and review the firms' adherence to the policies and procedures. A broker-dealer will need to be able to explain its credit risk analysis and ultimate determination to examiners as part of the examination process. If a broker-dealer has reasonable policies and procedures in place for determining credit risk, and those policies and procedures are followed, the potential for bias to be a part of the assessment process should be mitigated.

The Commission also considered mandating that broker-dealers use a certain number of factors or specific factors when making a credit risk determination. Ultimately, the Commission decided that allowing broker-dealers to establish policies and procedures that are tailored to the size and activities of the broker-dealer would keep costs down. Further, a given factor may be appropriate only for certain types of positions and could, if applied inappropriately, lead to inaccurate credit risk determinations. Allowing a broker-dealer the flexibility in selecting the factors it uses to assess the credit risk of its portfolio could lead to more accurate credit risk determinations.

In adopting the amendments to Appendices E and F of Rule 15c3–1, the Commission considered the alternative proposed by commenters that the minimal amount of credit risk standard be used. However, as explained earlier, the Commission does not believe such a standard would work in Appendices E and F because the minimal amount of credit risk standard in Rule 15c3–1 replaced a binary NRSRO credit rating standard under which the application of a lower or higher haircut amount depends on whether the commercial paper is rated in the top three rating categories and the nonconvertible debt and preferred stock is rated in the top four rating categories. Thus, the instrument either meets the requirement to apply the lower haircut or is subject to the higher haircut. The NRSRO credit ratings standard in Appendices E and F to Rule 15c3–1 is not binary because there are three gradations for credit risk weights. Thus, the minimal amount of credit risk standard would not be a suitable replacement.[305]

2. Exhibit A to Rule 15c3–3

In adopting the amendments to Exhibit A to Rule 15c3–3, the Commission did not consider any alternatives to the proposal and did not receive comments offering any alternatives to the proposal. The Commission could have established an alternative criterion but chose not to because the remaining three criteria in the rule are alternatives that permit broker-dealers to meet the objectives of the rule.

3. Rule 10b–10

In adopting the amendments to Rule 10b–10, the Commission considered not deleting paragraph (a)(8) as proposed. The Commission also considered requiring broker-dealers to disclose alternative information relating to the credit risk of certain debt securities. The Commission determined, however, that requiring the disclosure of alternative information regarding credit risk associated with debt securities similar to that required by paragraph (a)(8) would be inconsistent with the goal of reducing investors' reliance on credit ratings. Elevating an alternative measure of credit risk to the status now conferred upon NRSRO ratings by paragraph (a)(8) would merely substitute one standard upon which investors may have come to rely upon excessively for another. Prohibiting any reference to NRSRO credit ratings in confirmations, however, would seem to go too far by preventing broker-dealers from including information that they believe a reasonable investor would want to consider in particular circumstances. The Commission also determined that substituting another credit risk-related disclosure requirement for paragraph (a)(8) was unnecessary, given that credit risk information is likely to be disclosed before a transaction for reasons independent of paragraph (a)(8),[306] and given the other disclosures required by Rule 10b–10 in connection with

[303] *See Bond Dealers Letter,* at 3; *SIFMA Letter,* at 11.

[304] *Bond Dealers Letter,* at 3.

[305] *See* sections II.B.1.c.iii. and II.B.1.d.iii., *supra.*

[306] *See Confirmation of Transactions,* at 59 FR 59617 (explaining that the information required by paragraph (a)(8) should, in most cases, ''verify information that was disclosed to the investor prior to the transaction.'').

transactions in certain asset-backed securities.[307]

V. Final Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980 (''RFA'') [308] requires the Commission, in promulgating rules, to consider the impact of those rules on small entities. An Initial Regulatory Flexibility Act Analysis was prepared in accordance with the Regulatory Flexibility Act and included in the proposing release. The Commission certified in the proposing release, pursuant to section 605(b) of the RFA,[309] that the proposed rule would not, if adopted, have a significant impact on a substantial number of small entities. The Commission received no comments on this certification.

For purposes of Commission rulemaking in connection with the RFA, small entities include broker-dealers with total capital (net worth plus subordinated liabilities) of less than $500,000 on the date in the prior fiscal year as of which its audited financial statements were prepared pursuant to Rule 17a–5 under the Exchange Act,[310] or, if not required to file such statements, a broker or dealer that had total capital (net worth plus subordinated liabilities) of less than $500,000 on the last day of the preceding fiscal year (or in the time that it has been in business, if shorter) and is not affiliated with any person (other than a natural person) that is not a small business or small organization.[311]

The amendments adopted today relating to the securities haircut provisions in Rule 15c3–1 and the conforming amendment to Rule 17a–4 will not have a significant economic impact on a small number of entities. Only seven of the 434 broker-dealers that hold proprietary debt positions are considered small for purposes of the RFA and, in the staff's experience, broker-dealers with less than $500,000 in total capital typically hold very few proprietary securities positions and, in particular, a small number of debt securities. Thus, there are few small entities that will be impacted by these amendments. In addition, the amendments allow broker-dealers that hold these debt positions, including those broker-dealers that are considered small for purposes of the RFA, to establish policies and procedures that rely on only a few factors to keep costs low. Further, a small broker-dealer could choose to take the 15% catchall haircut instead of establishing policies and procedures if it determines such an approach is cost-effective. Accordingly, the amendments will not have a significant economic impact on a substantial number of small entities because even if the small entities have to change their current process, they can do so in such a way to minimize economic impact and still comply with the rule amendments.

The amendment to Appendix A to Rule 15c3–1 will not result in a significant impact on small entities. Although the definition of *major market foreign currency* will change, the Commission does not intend that the currencies that meet the definition of major market foreign currency will change because the currency will still have to have a substantial inter-bank forward currency market. Consequently, the amendments should not have a significant impact on broker-dealers, including small broker-dealers. Furthermore, the broker-dealers that operate under Appendix A to Rule 15c3–1 generally are market makers and trading firms that are not small entities as defined in Rule 0–10.

The amendments to the Appendices E and F to Rule 15c3–1 (which include conforming amendments to Appendix G to Rule 15c3–1 and the General Instructions to Form X–17A–5, Part IIB) will not apply to small entities. Appendices E and G apply to ANC broker-dealers and Appendix F and Form X–17A–5, Part IIB apply to OTC derivatives dealers. The ANC broker-dealers and the OTC derivatives dealers are not small entities as defined in Rule 0–10.

The amendments to Exhibit A to Rule 15c3–3 will not have a significant economic impact on a substantial number of small entities. As noted above, the OCC is the only clearing agency that meets the criteria to qualify for the debit for purposes of the reserve computation. The fact that the OCC meets the criteria to qualify for the debit is well understood among broker-dealers, including small broker-dealers.

The amendment to Rule 10b–10 will not have a significant economic impact on a substantial number of small entities. While a number of the broker-dealers that effect transactions in the debt securities currently subject to paragraph (a)(8) may be small entities, the Commission believes that it is uncommon for small broker-dealers to issue confirmations.[312] The Commission does not have a precise numerical estimate of the small broker-dealers that issue confirmations in connection with transactions in securities covered by paragraph (a)(8). The Commission believes, however, that the number is unlikely to be significant. In addition, the Commission continues to believe that the proposed amendment should not result in any significant change to the cost of providing confirmations to customers in connection with transactions in securities covered by paragraph (a)(8). Consequently, the Commission continues to believe that the removal of paragraph (a)(8) from Rule 10b–10 should not have a significant economic impact on a substantial number of small entities.

For the reasons described above, the Commission again certifies that the amendments to Rule 15c3–1, Appendices A, E, F, and G to Rule 15c3–1, Exhibit A to Rule 15c3–3, Rule 17a–4, the General Instructions to Form X–17A–5, Part IIB, and Rule 10b–10 will not have a significant economic impact on a substantial number of small entities.

VI. Statutory Basis and Text of the Proposed Amendments

Pursuant to the Exchange Act, 15 U.S.C. 78a *et seq.,* and particularly, Sections 3(b), 15, 23(a), and 36 (15 U.S.C. 78c(b), 78*o,* 78w(a), and 78mm), thereof, and Sections 939 and 939A of the Dodd-Frank Act, the Commission is amending §§ 240.10b–10, 240.15c3–1, 240.15c3–1a, 240.15c3–1e, 240.15c3–1f, 240.15c3–1g, 240.15c3–3a, 240.17a–4, and Form X–17A–5 Part IIB General Instructions under the Exchange Act.

List of Subjects in 17 CFR Parts 240 and 249

Brokers, Fraud, Reporting and recordkeeping requirements, Securities.

Text of Amendment

In accordance with the foregoing, Title 17, Chapter II of the Code of Federal Regulations is amended as follows:

PART 240—GENERAL RULES AND REGULATIONS, SECURITIES EXCHANGE ACT OF 1934

■ 1. The authority citation for part 240 is amended by revising the general authority and adding sectional authorities for §§ 240.15c3–1a, 240.15c3–1e, 240.15c3–1f, 240.15c3–1g

[307] For example, in connection with transactions in certain asset-backed securities, paragraphs (a)(4) through (a)(7) of Rule 10b–10 require disclosure of information relating to prepayment risk and yield information.

[308] 5 U.S.C. 601 *et seq.*

[309] *See* 5 U.S.C. 605(b).

[310] *See* 17 CFR 240.17a–5(d).

[311] *See* 17 CFR 240.0–10(c).

[312] The Commission understands that most small broker-dealers introduce their accounts to clearing firms that, in turn, would typically issue the confirmations.

and § 240.15c3–3a in numerical order to read as follows:

Authority: 15 U.S.C. 77c, 77d, 77g, 77j, 77s, 77z–2, 77z–3, 77eee, 77ggg, 77nnn, 77sss, 77ttt, 78c, 78c–3, 78c–5, 78d, 78e, 78f, 78g, 78i, 78j, 78j–1, 78k, 78k–1, 78*l,* 78m, 78n, 78n–1, 78*o,* 78*o*–4, 78*o*–10, 78p, 78q, 78q–1, 78s, 78u–5, 78w, 78x, 78*ll,* 78mm, 80a–20, 80a–23, 80a–29, 80a–37, 80b–3, 80b–4, 80b–11, 7201 *et seq.,* and 8302; 7 U.S.C. 2(c)(2)(E); 12 U.S.C. 5221(e)(3); 18 U.S.C. 1350, unless otherwise noted.

* * * * *

Sections 240.15c3–1a, 240.15c3–1e, 240.15c3–1f, 240.15c3–1g are also issued under Pub. L. 111–203, secs. 939, 939A, 124. Stat. 1376 (2010) (15 U.S.C. 78c, 15 U.S.C. 78*o*–7 note).

* * * * *

Section 240.15c3–3a is also issued under Pub. L. 111–203, §§ 939, 939A, 124. Stat. 1376 (2010) (15 U.S.C. 78c, 15 U.S.C. 78*o*–7 note).

* * * * *

§ 240.10b–10 [Amended]

■ 2. Section 240.10b–10 is amended by removing paragraph (a)(8) and redesignating paragraph (a)(9) as paragraph (a)(8).

■ 3. Section 240.15c3–1 is amended by:

■ a. Revising paragraphs (c)(2)(vi)(E) introductory text, (c)(2)(vi)(F)(*1*) introductory text, (c)(2)(vi)(F)(*2*) introductory text, and (c)(2)(vi)(H); and

■ b. Adding paragraph (c)(2)(vi)(I).

The revisions and addition read as follows:

§ 240.15c3–1 Net capital requirements for brokers or dealers.

* * * * *

(c) * * *

(2) * * *

(vi) * * *

(E) *Commercial paper, bankers' acceptances and certificates of deposit.* In the case of any short term promissory note or evidence of indebtedness which has a fixed rate of interest or is sold at a discount, which has a maturity date at date of issuance not exceeding nine months exclusive of days of grace, or any renewal thereof, the maturity of which is likewise limited and has only a minimal amount of credit risk, or in the case of any negotiable certificates of deposit or bankers' acceptance or similar type of instrument issued or guaranteed by any bank as defined in section 3(a)(6) of the Securities Exchange Act of 1934 (15 U.S.C. 78c(a)(6)), the applicable percentage of the market value of the greater of the long or short position in each of the categories specified below are:

* * * * *

(F)(*1*) *Nonconvertible debt securities.* In the case of nonconvertible debt securities having a fixed interest rate and a fixed maturity date, which are not traded flat or in default as to principal or interest and which have only a minimal amount of credit risk, the applicable percentages of the market value of the greater of the long or short position in each of the categories specified below are:

* * * * *

(*2*) A broker or dealer may elect to exclude from the above categories long or short positions that are hedged with short or long positions in securities issued by the United States or any agency thereof or nonconvertible debt securities having a fixed interest rate and a fixed maturity date and which are not traded flat or in default as to principal or interest, and which have only a minimal amount of credit risk if such securities have maturity dates:

* * * * *

(H) In the case of cumulative, non-convertible preferred stock ranking prior to all other classes of stock of the same issuer, which has only a minimal amount of credit risk and which are not in arrears as to dividends, the deduction shall be 10% of the market value of the greater of the long or short position.

(I) In order to apply a deduction under paragraphs (c)(2)(vi)(E), (c)(2)(vi)(F)(*1*), (c)(2)(vi)(F)(*2*), or (c)(2)(vi)(H) of this section, the broker or dealer must assess the creditworthiness of the security or money market instrument pursuant to policies and procedures for assessing and monitoring creditworthiness that the broker or dealer establishes, documents, maintains, and enforces. The policies and procedures must be reasonably designed for the purpose of determining whether a security or money market instrument has only a minimal amount of credit risk. Policies and procedures that are reasonably designed for this purpose should result in assessments of creditworthiness that typically are consistent with market data. A broker-dealer that opts not to make an assessment of creditworthiness under this paragraph may not apply the deductions under paragraphs (c)(2)(vi)(E), (c)(2)(vi)(F)(1), (c)(2)(vi)(F)(2), or (c)(2)(vi)(H) of this section.

Note to paragraph (c)(2)(vi)(I): For a discussion of the ''minimal amount of credit risk'' standard, *see Removal of Certain References to Credit Ratings Under the Securities Exchange Act of 1934,* Exchange Act Release No. 34–71194 (Dec. 27, 2013), at *http://www.sec.gov/rules/final.shtml.*

* * * * *

§ 240.15c3–1a [Amended]

■ 4. Section 240.15c3–1a, paragraph (b)(1)(i)(C), is amended by removing the phrase ''whose short term debt is rated in one of the two highest categories by at least two nationally recognized statistical rating organizations and'' and by removing the last sentence.

■ 5. Section 240.15c3–1e is amended by:

■ a. Revising the introductory text in paragraph (c)(4)(vi);

■ b. Removing paragraphs (c)(4)(vi)(A) through (c)(4)(iv)(D);

■ c. Redesignating paragraphs (c)(4)(vi)(E), (F), and (G) as paragraphs (c)(4)(vi)(A), (B), and (C), respectively; and

■ d. Revising newly redesignated paragraph (c)(4)(vi)(A).

The revisions read as follows:

§ 240.15c3–1e Deductions for market and credit risk for certain brokers or dealers (Appendix E to 17 CFR 240.15c3–1).

* * * * *

(c) * * *

(4) * * *

(vi) *Credit risk weights of counterparties.* A broker or dealer that computes its deductions for credit risk pursuant to this Appendix E shall apply a credit risk weight for transactions with a counterparty of either 20%, 50%, or 150% based on an internal credit rating the broker or dealer determines for the counterparty.

(A) As part of its initial application or in an amendment, the broker or dealer may request Commission approval to apply a credit risk weight of either 20%, 50%, or 150% based on internal calculations of credit ratings, including internal estimates of the maturity adjustment. Based on the strength of the broker's or dealer's internal credit risk management system, the Commission may approve the application. The broker or dealer must make and keep current a record of the basis for the credit rating of each counterparty;

* * * * *

■ 6. Section 240.15c3–1f is amended by:

■ a. Removing from paragraph (d)(2) introductory text the phrase ''the counterparty factor. The counter party factors are:'' and adding in its place ''a counterparty factor of 20%, 50%, or 100% based on an internal credit rating the OTC derivatives dealer determines for the counterparty; and'';

■ b. Removing paragraphs (d)(2)(i) through (d)(2)(iii); and

■ c. Revising paragraphs (d)(3)(i), (d)(3)(ii), (d)(3)(iii), and (d)(4).

The revisions read as follows:

§ 240.15c3–1f Optional market and credit risk requirements for OTC derivatives dealers (Appendix F to 17 CFR 240.15c3–1).

* * * * *

(d) * * *

(3) * * *

(i) For counterparties for which an OTC derivatives dealer assigns an internal rating for senior unsecured long-term debt or commercial paper that would apply a 20% counterparty factor under paragraph (d)(2) of this section, 5% of the amount of the net replacement value in excess of 25% of the OTC derivatives dealer's tentative net capital;

(ii) For counterparties for which an OTC derivatives dealer assigns an internal rating for senior unsecured long-term debt that would apply a 50% counterparty factor under paragraph (d)(2) of this section, 20% of the amount of the net replacement value in excess of 25% of the OTC derivatives dealer's tentative net capital;

(iii) For counterparties for which an OTC derivatives dealer assigns an internal rating for senior unsecured long-term debt that would apply a 100% counterparty factor under paragraph (d)(2) of this section, 50% of the amount of the net replacement value in excess of 25% of the OTC derivatives dealer's tentative net capital.

(4) Counterparties may be rated by the OTC derivatives dealer, or by an affiliated bank or affiliated broker-dealer of the OTC derivatives dealer, upon approval by the Commission on application by the OTC derivatives dealer. Based on the strength of the OTC derivatives dealer's internal credit risk management system, the Commission may approve the application. The OTC derivatives dealer must make and keep current a record of the basis for the credit rating for each counterparty.

* * * * *

§ 240.15c3–1g [Amended]

■ 7. Section 240.15c3–1g(a)(3)(i)(F) is amended by removing the phrase ''paragraphs (c)(4)(vi)(D) and (c)(4)(vi)(E)'' and adding in its place ''paragraphs (c)(4)(vi)(A) and (c)(4)(vi)(B)''.

§ 240.15c3–3a [Amended]

■ 8. Section 240.15c3–3a is amended by removing paragraph (b)(1)(i) of Note G and redesignating paragraphs (b)(1)(ii), (iii), and (iv) of Note G as paragraphs (b)(1)(i), (ii), and (iii), respectively.

■ 9. Section 240.17a–4 is amended by:

■ a. Removing from paragraph (b)(12) the phrase ''§ 240.15c3–1e(c)(4)(vi)(D) and (E)'' and adding in its place ''§ 240.15c3–1e(c)(4)(vi) ''; and

■ b. Adding paragraph (b)(13).

The addition reads as follows:

§ 240.17a–4 Records to be preserved by certain exchange members, brokers and dealers.

* * * * *

(b) * * *

(13) The written policies and procedures the broker-dealer establishes, documents, maintains, and enforces to assess creditworthiness for the purpose of § 240.15c3–1(c)(2)(vi)(E), (c)(2)(vi)(F)(*1*), (c)(2)(vi)(F)(*2*), and (c)(2)(vi)(H).

* * * * *

PART 249—FORMS, SECURITIES EXCHANGE ACT OF 1934

■ 10. The authority citation for Part 249 is amended by adding a sectional authority for § 249.617 in numerical order to read as follows:

Authority: 15 U.S.C. 78a *et seq.* and 7201 *et. seq.;* 12 U.S.C. 5461 *et seq.;* and 18 U.S.C. 1350, unless otherwise noted.

* * * * *

Section 249.617 is also issued under Pub. L. 111–203, §§ 939, 939A, 124. Stat. 1376 (2010) (15 U.S.C. 78c, 15 U.S.C. 78*o*–7 note).

* * * * *

■ 11. Amend Form X–17A–5 Part IIB General Instructions (referenced in § 249.617) by:

■ a. Removing Schedule IV: Internal Credit Rating Conversion; and

■ b. Removing all but the first sentence in the section ''Credit risk exposure'' under the heading ''Computation of Net Capital and Required Net Capital,'' and adding a second sentence that reads ''The counter-party charge is computed using the credit risk weights assigned to the OTC derivatives dealer's internal calculations by the Commission under paragraph (d)(2) of Appendix F.''

Note: The text of Form X–17A–5 Part IIB does not, and this amendment will not, appear in the Code of Federal Regulations.

* * * * *

By the Commission.

Dated: December 27, 2013.

Lynn M. Powalski,

Deputy Secretary.

[FR Doc. 2013–31426 Filed 1–7–14; 8:45 am]

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Part IV

Department of the Interior

Fish and Wildlife Service

50 CFR Part 17

Endangered and Threatened Wildlife and Plants; Designation of Critical Habitat for Chromolaena frustrata (Cape Sable Thoroughwort); Final Rule

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

[Docket No. FWS–R4–ES–2013–0029; 4500030113]

RIN 1018–AZ51

Endangered and Threatened Wildlife and Plants; Designation of Critical Habitat for Chromolaena frustrata (Cape Sable Thoroughwort)

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Final rule.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), designate critical habitat for the *Chromolaena frustrata* (Cape Sable thoroughwort) under the Endangered Species Act of 1973, as amended (Act). In total, approximately 10,968 acres (4,439 hectares) in Miami-Dade and Monroe Counties, Florida, fall within the boundaries of the critical habitat designation. The effect of this regulation is to designate critical habitat for this species under the Act for the conservation of the species.

DATES: This rule is effective on February 7, 2014.

ADDRESSES: This final rule is available on the Internet at *http://www.regulations.gov* and *http://www.fws.gov/verobeach/.* Comments and materials we received, as well as supporting documentation used in preparation of this rule, are available for public inspection at *http://www.regulations.gov.* All of the comments, materials, and documentation that we considered in this rulemaking are available by appointment, during normal business hours, at the U.S. Fish and Wildlife Service, South Florida Ecological Services Office, 1339 20th Street, Vero Beach, FL 32960; by telephone 772–562–3909; or by facsimile 772–562–4288.

The coordinates, plot points, or both from which the maps are generated are included in the administrative record for this critical habitat designation and are available at *http://www.regulations.gov,* Docket No. FWS–R4–ES–2013–0029, and at the U.S. Fish and Wildlife Service, South Florida Ecological Services Office at *http://www.fws.gov/verobeach/* (see **FOR FURTHER INFORMATION CONTACT**). Any additional tools or supporting information that we developed for this critical habitat designation will also be available at the Fish and Wildlife Service Web site and Field Office set out above, and may also be included in the preamble of this rule and at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Larry Williams, Field Supervisor, U.S. Fish and Wildlife Service, South Florida Ecological Services Office, 1339 20th Street, Vero Beach, FL 32960; telephone 772–562–3909; or facsimile 772–562–4288. If you use a use a telecommunications device for the deaf (TDD), call the Federal Information Relay Service (FIRS) at 800–877–8339.

SUPPLEMENTARY INFORMATION:

Executive Summary

Why we need to publish a rule. Under section 4(a)(3) of the Endangered Species Act (Act), when we determine that a species is endangered or threatened, we are required to designate critical habitat, to the maximum extent prudent and determinable. Designations of critical habitat can only be completed by issuing a rule.

We published our determination for *Chromolaena frustrata* as an endangered species on October 24, 2013 (78 FR 63796). On October 11, 2012 (77 FR 61836), we published in the **Federal Register** a proposed critical habitat designation for *C. frustrata.*

The areas we are designating in this rule constitute our current best assessment of the areas that meet the definition of critical habitat for *Chromolaena frustrata.* In total, we are designating approximately 10,968 acres (4,439 hectares), in nine units, as critical habitat for *C. frustrata.*

We have prepared an economic analysis of the designation of critical habitat. Section 4(b)(2) of the Act states that the Secretary shall designate critical habitat on the basis of the best scientific data, after taking into consideration the economic impact, national security impact, and any other relevant impact of specifying any particular areas as critical habitat. In accordance with section 4(b)(2) of the Act, we have prepared an analysis of the economic impacts of the critical habitat designation and related factors. We announced the availability of the draft economic analysis (DEA) in the **Federal Register** on July 8, 2013 (78 FR 40669), and sought comments from the public. We have incorporated the comments and have completed the final economic analysis (FEA) concurrently with this final designation.

Peer review and public comment. We sought comments from seven independent specialists to ensure that our designation is based on scientifically sound data, assumptions, and analyses. We obtained review from three knowledgeable individuals with scientific expertise to review our technical assumptions and analysis, and to determine whether or not we had used the best available information. These peer reviewers generally concurred with our methods and conclusions, and they provided additional information, clarifications, and suggestions to improve this final rule. Information we received from peer review is incorporated in this final designation. We considered all comments and information we received from the public during the comment periods.

Previous Federal Actions

On October 11, 2012, we published a proposed rule to list *Chromolaena frustrata* under the Act (16 U.S.C. 1531 *et seq.*) and designate critical habitat for *C. frustrata* (77 FR 61836). All Federal actions related to protection under the Act for this species, prior to October 11, 2012, are outlined in the preamble to the proposed rule. On July 8, 2013 (78 FR 40669), we reopened the comment period on the proposed rule and announced the availability of the draft economic analysis for the proposed critical habitat designation.

Summary of Comments and Recommendations

We requested that the public submit written comments on the proposed designation of critical habitat for *Chromolaena frustrata* during two comment periods. The first comment period opened with the publication of the proposed rule on October 11, 2012, and closed on December 10, 2012 (77 FR 61836). The second comment period opened with the document published on July 8, 2013 (78 FR 40669), that made available and requested public comments on the draft economic analysis of the proposed critical habitat designation and that reopened the public comment period on the proposed listing and critical habitat designation. For that second comment period, we accepted public comments from July 8, 2013, through August 7, 2013 (78 FR 40669). We also contacted appropriate Federal, State, and local agencies; scientific organizations; and other interested parties and invited them to comment on the proposed rule and draft economic analysis during these comment periods. In addition, in October 2012, we published a total of six legal public notices on the proposed rule in the areas of south Florida affected by the designation. We did not receive any requests for a public hearing during either comment period.

The October 11, 2012, proposed rule contained both the proposed listing of *Chromolaena frustrata, Consolea corallicola,* and *Harrisia aboriginum,* as well as the proposed designation of critical habitat for *Chromolaena frustrata.* Therefore, we received combined comments from the public on both actions. However, in this final rule, we address only those comments that apply to the designation of critical habitat for *Chromolaena frustrata.* During the first comment period, we received one letter directly commenting on the proposed critical habitat designation for *Chromolaena frustrata.* During the second comment period, we received one letter commenting on the proposed critical habitat designation.

All substantive information provided during the comment periods specifically relating to the proposed critical habitat designation for *Chromolaena frustrata* is addressed in the following summary and incorporated into this final rule as appropriate.

Peer Reviewer Comments

In accordance with our peer review policy published on July 1, 1994 (59 FR 34270), we solicited expert opinions from seven knowledgeable individuals with scientific expertise that included familiarity with the species, the geographic region in which the species occurs, and conservation biology principles. Of those, three reviewers were experts on *Chromolaena frustrata.* We received responses from six of the peer reviewers including the experts on *C. frustrata.*

We reviewed all comments we received from the peer reviewers for substantive issues and new information regarding critical habitat for *Chromolaena frustrata.* The peer reviewers generally concurred with our methods and conclusions and provided additional information, clarifications, and suggestions to improve this final critical habitat rule. Two peer reviewer comments are addressed in the following summary and incorporated into this final rule as appropriate.

(1) *Comment:* One peer reviewer indicated that rockland hammock does not occur in the coastal area of Everglades National Park (ENP). Instead, the commenter indicated the habitat in ENP where *Chromolaena frustrata* occurs should be classified as coastal hardwood hammock.

Our Response: Unit 1 (ENP) includes the areas and habitats referred to by the peer reviewer. The Service misapplied the name rockland hammock to the coastal hardwood hammock habitat (*sensu* Rutchey *et al.* 2006, p. 21) present within this unit. While similar in overall vegetation structure and disturbance regime, coastal hardwood hammock differs from rockland hammock in that it develops on elevated marl ridges with a thin layer of organic matter, as opposed to exposed limestone. The plant species composition of coastal hardwood hammock also differs somewhat from rockland hammock. These clarifications have been incorporated in the ''Habitat'' and ''Distribution and Range'' sections; and the *Physical or Biological Features* and *Primary Constituent Elements for* Chromolaena frustrata sections of this final rule. No changes were made to the unit boundaries because of this change in classification of the habitat.

(2) *Comment:* One peer reviewer indicated that coastal berm does not occur within the critical habitat proposed in ENP.

Our Response: The Service incorrectly thought that coastal berm habitat was present in Unit 1 (ENP). ENP staff confirmed that this is not the case. We removed references to coastal berm in Unit 1 in the unit description.

Comments From States

The proposed designation of critical habitat for *Chromolaena frustrata* occurs only in the State of Florida. The Florida Department of Agriculture and Consumer Services (FDACS), Florida Forest Service, an agency that administers a grant program for imperiled plant species in Florida, provided only peer review comments on the proposed rule. The FDACS, Division of Plant Industry, the agency responsible for permits for collecting or harvesting State-protected plants in Florida, was notified by Service staff of the reopening of the comment period and notice of availability of the economic analysis, and that Division provided official comments supporting the designation of critical habitat for the plant.

Public Comments

(3) *Comment:* One commenter indicated that critical habitat designation for *Chromolaena frustrata* should explicitly include both occupied and unoccupied habitat areas that will buffer this species from climate change, and the Service should explain how these areas will be sufficient to ensure the species' persistence in the face of ongoing sea-level rise.

Our Response: The sea-level rise projections discussed under Factor E (see the proposed listing rule, 77 FR 61836) suggest that much of the proposed critical habitat for *Chromolaena frustrata* could be lost to sea-level rise by 2100 if high-end projections approaching 6.6 feet (ft) (2 meters (m)) become a reality. This critical habitat designation for *C. frustrata* includes both occupied and unoccupied habitat at the highest elevation areas available within the species' historical range in the Florida Keys, so as to provide suitable upland habitat for the longest possible time before these areas are lost to sea-level rise. The highest sea-level rise of 5.9 ft (1.8 m) forecast for this area based on inundation modeling indicates the higher elevation areas of Key Largo, Upper Matecumbe, and Lignumvitae Key will continue to support upland habitats to at least 2100. However, all other areas in the Florida Keys and areas that currently support *C. frustrata* in ENP may be lost to sea-level rise by 2100.

In the next 50 to 100 years, in order for *Chromolaena frustrata* to survive, reintroduction to suitable higher elevation sites outside of its historical range may be the only available option. However, the best available science is not able to project future locations of suitable habitat for *C. frustrata* on the Florida mainland, which will also be affected by sea-level rise within and outside the historical range of the plant. The range of sea-level rise projections coupled with the lack of models specific to the areas and habitats does not support identification of unoccupied areas of critical habitat for this species solely on the basis of the effects of climate change on the Florida mainland at this time.

(4) *Comment:* One commenter indicated there are ample precedent, legal authority, and conservation imperatives for the Service to identify and designate unoccupied inland habitat for the plant to buffer it from the effects of sea-level rise and increasing storm surge.

Our Response: As stated in the response to Comment 3, above, we agree that considerations should include whether unoccupied areas (including areas outside the historical range) are essential to the conservation of the species, including areas less vulnerable to sea-level rise and storm surge impacts in the future. We have endeavored to designate areas of habitat to serve these functions for *Chromolaena frustrata,* within the bounds of the best available science. We selected areas of higher elevation within suitable habitat on each of the Florida Keys within the species' historical range with the expectation that these areas will be less vulnerable to storm surge and will retain the physical and biological features that support *Chromolaena frustrata* for a longer duration than

many of the sites where the species exists currently. However, the best available science is not able to project future locations of suitable habitat for the species on the Florida mainland. Therefore, we did not designate unoccupied critical habitat solely on the basis of the effects of climate change.

Summary of Changes From Proposed Rule

Based on information we received in comments regarding the habitats that support *Chromolaena frustrata,* we refined our description of the primary constituent elements to more accurately reflect the habitat needs of the species. Specifically, habitats in ENP previously identified as rockland hammock were reclassified as coastal hardwood hammock to account for the different substrate on which these communities develop and subtle differences in species composition. No adjustments to the unit boundaries were needed as a result of this change. A change, made throughout the final rule, was the clarification that plant species in each habitat community may be present, but are not limited to those native species listed in the vegetation description.

We corrected errors in the critical habitat unit acreage that were due to rounding errors. These rounding errors resulted in changes of no more than 1 to 3 ac (0 to 1 ha) in any given unit. We also corrected a calculation error in the acreage of Unit 1 (ENP). This error was due to a miscalculation of the unit size. In the proposed rule, we reported the area of Unit 1 as 3,768 ac (1,525 ha). In the final rule, we report the correct area, which is 6,166 ac (2,495 ha). The Service coordinated this change with ENP, who expressed no concern with the change, as their review focused on the mapped boundaries in the proposed rule, which correctly represented the proposed designated habitat. No adjustments to the unit boundaries were needed as a result of this change. This change does not affect the outcome of economic analysis for the proposed unit designations concerning the projection of incremental effects, as it is based on the consultation history in the mapped area, not the acres. The rounding error corrections and the unit 1 acreage correction results in the total acreage of designated critical habitat for *Chromolaena frustrata* to be 10,968 ac (4,439 ha).

Summary of Biological Status for Chromolaena frustrata

For more information on *Chromolaena frustrata's* taxonomy, life history, habitat, population descriptions, and factors affecting the species, refer to the proposed rule published in the **Federal Register** on October 11, 2012 (77 FR 61836).

We have evaluated the biological status of this species and threats affecting its continued existence. Our assessment, as summarized immediately below, is based upon the best available scientific and commercial data and the opinion of the species experts.

Chromolaena frustrata (Family: Asteraceae) is a perennial herbaceous plant. Mature plants are 5.9 to 9.8 inches (in) (15 to 25 centimeters (cm)) tall with erect stems. The blue to lavender flowers are borne in heads, usually in clusters of two to six. Flowers are produced mostly in the fall, though sometimes year round (Nesom 2006, pp. 544–545).

Taxonomy

Chromolaena frustrata was first reported by Chapman, from the Florida Keys in 1886, naming it *Eupatorium heteroclinium* (Chapman 1889, p. 626). Synonyms include *Eupatorium frustratum* B.L. Robinson and *Osmia frustrata* (B.L. Robinson) Small.

Climate

The climate of south Florida where *Chromolaena frustrata* occurs is classified as tropical savanna and is characterized by distinct wet and dry seasons, a monthly mean temperature above 64.4 degrees Fahrenheit (°F) (18 degrees Celsius (°C)) in every month of the year, and annual rainfall averaging 30 to 60 in (75 to 150 cm) (Gabler *et al.* 1994, p. 211).

Habitat

Chromolaena frustrata grows in open canopy habitats in coastal berms and coastal rock barrens, and in semi-open to closed canopy habitats, including buttonwood forests, coastal hardwood hammocks, and rockland hammocks. *C. frustrata* is often found in the shade of associated canopy and subcanopy plant species; these canopies buffer *C. frustrata* from full exposure to the sun (Bradley and Gann 1999, p. 37).

Detailed descriptions of coastal berm, coastal rock barren, rockland hammock, and buttonwood forest are presented in the proposed listing rule for *Chromolaena frustrata, Consolea corallicola,* and *Harrisia aboriginum* (77 FR 61836; October 11, 2012). Peer reviewers provided new information identifying coastal hardwood hammock as the community type supporting *Chromolaena frustrata* in ENP and identified associated species found in buttonwood forest in ENP. We include a full description of the coastal hardwood hammock and a revised description of the buttonwood forest communities below.

Coastal Hardwood Hammock

Coastal hardwood hammock that supports *Chromolaena frustrata* in ENP is a species-rich, tropical hardwood forest. Though similar to rockland hammock in most characteristics, coastal hardwood hammock develops on a substrate consisting of elevated marl ridges with a very thin organic layer (Sadle 2012a, pers. comm.). Marl is an unconsolidated sedimentary rock or soil consisting of clay and lime. The plant species composition of coastal hardwood hammocks also differs somewhat from that of rockland hammock. Typical tree and shrub species may include, but are not limited to, *Capparis flexuosa* (bayleaf capertree), *Coccoloba diversifolia* (pigeon plum), *Piscidia piscipula* (Jamaican dogwood), *Sideroxylon foetidissimum* (false mastic), *Eugenia foetida* (Spanish stopper), *Swietenia mahagoni* (West Indies mahogany), *Ficus aurea* (strangler fig), *Sabal palmetto* (cabbage palm), *Eugenia axillaris* (white stopper), *Zanthoxylum fagara* (wild lime), *Sideroxylon celastrinum* (saffron plum), and *Colubrina arborescens* (greenheart) (Rutchey *et al.* 2006, p. 21). Herbaceous species in coastal hardwood forest may include, but are not limited to, *Acanthocereus tetragonus* (barbed wire or triangle cactus), *Alternanthera flavescens* (yellow joyweed), *Batis maritima* (saltwort or turtleweed), *Borrichia arborescens* (tree seaside oxeye), *Borrichia frutescens* (bushy seaside oxeye), *Caesalpinia bonduc* (grey nicker), *Capsicum annuum* (bird pepper), *Galactia striata* (Florida hammock milkpea), *Heliotropium angiospermum* (scorpion's tail), *Passiflora suberosa* (corkystem passionflower), *Rivina humilis* (pigeonberry), *Salicornia perennis* (perennial glasswort), *Sesuvium portulacastrum* (seapurslane), and *Suaeda linearis* (sea blite). Ground cover is often limited in closed canopy areas and abundant in areas where canopy disturbance has occurred or where this community intergrades with buttonwood forest (Sadle 2012a, pers. comm.).

The sparsely vegetated edges or interior portions of rockland and coastal hardwood hammock where the canopy is open are the areas that have light levels sufficient to support *Chromolaena frustrata.* However, the dynamic nature of the habitat means that areas not currently open may become open in the future as a result of canopy disruption from hurricanes,

while areas currently open may develop more dense canopy over time, eventually rendering that portion of the hammock unsuitable for *C. frustrata.*

Buttonwood Forest

Forests dominated by buttonwood often exist in upper tidal areas, especially where mangrove swamp transitions to rockland or coastal hardwood hammock. These buttonwood forests have canopy dominated by *Conocarpus erectus* (buttonwood) and often have an understory dominated by *Borrichia frutescens, Lycium carolinianum* (Christmasberry), and *Limonium carolinianum* (sea lavender) (Florida Natural Areas Inventory (FNAI) 2010d, p. 4). In ENP, the species most frequently observed in association with *Chromolaena frustrata* are *Capparis flexuosa, Borrichia frutescens, Alternanthera flavescens, Rivina humilis, Sideroxylon celastrinum, Heliotropium angiospermum, Eugenia foetida, Batis maritima, Acanthocereus tetragonus,* and *Sesuvium portulacastrum* (Sadle 2012a, pers. comm.).

Temperature, salinity, tidal fluctuation, substrate, and wave energy influence the size and extent of buttonwood forests (FNAI 2010e, p. 3). Buttonwood forests often grade into salt marsh, coastal berm, rockland hammock, coastal hardwood hammock, and coastal rock barren (FNAI 2010d, p. 5).

Distribution and Range

Chromolaena frustrata is endemic to the southern tip of Florida and the Florida Keys. It occurs within coastal berm, coastal rock barrens, coastal hardwood hammock, rockland hammock, and buttonwood forest habitat. The estimated rangewide population was 6,500 to 7,500 plants when the eight known populations were last surveyed (Bradley and Gann 2004, pp. 3–6; Sadle 2012a, pers. comm.; Duquesnel 2012, pers. comm.). Four of eight extant *C. frustrata* populations consist of fewer than 100 individuals. These populations may not be viable in the long term due to their small number of individuals.

Chromolaena frustrata was historically known from Monroe County, both on the Florida mainland and the Florida Keys, and in Miami-Dade County along Florida Bay in ENP (Bradley and Gann 1999, p. 36). In the Florida Keys, *C. frustrata* was observed historically on Big Pine Key, Boca Grande Key, Fiesta Key, Key Largo, Key West, Knight's Key, Lignumvitae Key, Long Key, Upper Matecumbe Key, and Lower Matecumbe Key (Bradley and Gann 1999, p. 36; Bradley and Gann 2004, pp. 4–7). *Chromolaena frustrata* has been extirpated from half of the islands where it occurred in the Florida Keys, but appears to occupy its historical distribution in ENP. Although remaining *C. frustrata* populations occur mostly within public conservation lands, threats to the species from a wide array of natural and anthropogenic sources still remain. Habitat loss and modification, recreation impacts, and competition from nonnative plant species still exist in all remaining populations. Additionally, much of the species' habitat is projected to be lost to sea-level rise over the next century.

In ENP, 11 *Chromolaena frustrata* subpopulations supporting approximately 1,600 to 2,600 plants occur in buttonwood forests and coastal hardwood hammocks from the Coastal Prairie Trail near the southern tip of Cape Sable to Madeira Bay (Sadle 2007 and 2012b, pers. comm.).

In the Florida Keys, *Chromolaena frustrata* is now known only from Upper Matecumbe Key, Lower Matecumbe Key, Lignumvitae Key, Long Key, Big Munson Island, and Boca Grande Key (Bradley and Gann 2004, pp. 3–4). It no longer exists on Key Largo, Big Pine Key, Fiesta Key, Knight's Key, or Key West (Bradley and Gann 2004, pp. 4–6).

Reproductive Biology and Genetics

The reproductive biology and genetics of *Chromolaena frustrata* have received little study. Fresh *C. frustrata* seeds show a germination rate of 65 percent, but germination rates decrease to 27 percent after the seeds are subjected to freezing, suggesting that long-term seed storage may present difficulties (Kennedy *et al.* 2012, pp. 40, 50–51). While there have been no studies on the reproductive biology of *C. frustrata,* we can draw some generalizations from other species of *Chromolaena,* which reproduce sexually. New plants originate from seeds. Pollinators are likely to be generalists, such as butterflies, bees, flies, and beetles. Seed dispersal is largely by wind (Lakshmi *et al.* 2011, p. 1).

Population Demographics

Chromolaena frustrata is relatively a short-lived plant; therefore it must successfully reproduce more often than a long-lived species to maintain populations. *C. frustrata* populations are demographically unstable, experiencing sudden steep declines due to the effects of hurricanes and storm surges. However, the species appears to be able to rebound at affected sites within a few years (Bradley 2009, pers. comm.). The large population observed at Big Munson Island in 2003 likely resulted from thinning of the rockland hammock canopy caused by Hurricane Georges in 1998 (Bradley and Gann 2004, p. 4). Populations that are subject to wide demographic fluctuations are generally more vulnerable to random extinction events and negative consequences arising from small populations, such as genetic bottlenecks.

Critical Habitat

Background

Critical habitat is defined in section 3 of the Act as:

(1) The specific areas within the geographical area occupied by the species, at the time it is listed in accordance with the Act, on which are found those physical or biological features

(a) Essential to the conservation of the species, and

(b) Which may require special management considerations or protection; and

(2) Specific areas outside the geographical area occupied by the species at the time it is listed, upon a determination that such areas are essential for the conservation of the species.

Conservation, as defined under section 3 of the Act, means to use and the use of all methods and procedures that are necessary to bring an endangered or threatened species to the point at which the measures provided pursuant to the Act are no longer necessary. Such methods and procedures include, but are not limited to, all activities associated with scientific resources management such as research, census, law enforcement, habitat acquisition and maintenance, propagation, live trapping, and transplantation, and, in the extraordinary case where population pressures within a given ecosystem cannot be otherwise relieved, may include regulated taking.

Critical habitat receives protection under section 7 of the Act through the requirement that Federal agencies ensure, in consultation with the Service, that any action they authorize, fund, or carry out is not likely to result in the destruction or adverse modification of critical habitat. The designation of critical habitat does not affect land ownership or establish a refuge, wilderness, reserve, preserve, or other conservation area. Such designation does not allow the government or public to access private lands. Such designation does not require implementation of restoration, recovery, or enhancement measures by non-

Federal landowners. Where a landowner requests Federal agency funding or authorization for an action that may affect a listed species or critical habitat, the consultation requirements of section 7(a)(2) of the Act would apply, but even in the event of a destruction or adverse modification finding, the obligation of the Federal action agency and the landowner is not to restore or recover the species, but to implement reasonable and prudent alternatives to avoid destruction or adverse modification of critical habitat.

Under the first prong of the Act's definition of critical habitat, areas within the geographical area occupied by the species at the time it was listed are included in a critical habitat designation if they contain physical or biological features (1) which are essential to the conservation of the species and (2) which may require special management considerations or protection. For these areas, critical habitat designations identify, to the extent known using the best scientific and commercial data available, those physical or biological features that are essential to the conservation of the species (such as space, food, cover, and protected habitat). In identifying those physical or biological features within an area, we focus on the principal biological or physical constituent elements (primary constituent elements such as roost sites, nesting grounds, seasonal wetlands, water quality, tide, soil type) that are essential to the conservation of the species. Primary constituent elements are those specific elements of the physical or biological features that provide for a species' life-history processes and are essential to the conservation of the species.

Under the second prong of the Act's definition of critical habitat, we can designate critical habitat in areas outside the geographical area occupied by the species at the time it is listed, upon a determination that such areas are essential for the conservation of the species. For example, an area currently occupied by the species but that was not occupied at the time of listing may be essential to the conservation of the species and may be included in the critical habitat designation. We designate critical habitat in areas outside the geographical area occupied by a species only when a designation limited to its range would be inadequate to ensure the conservation of the species.

Section 4 of the Act requires that we designate critical habitat on the basis of the best scientific and commercial data available. Further, our Policy on Information Standards Under the Endangered Species Act (published in the **Federal Register** on July 1, 1994 (59 FR 34271)), the Information Quality Act (section 515 of the Treasury and General Government Appropriations Act for Fiscal Year 2001 (Pub. L. 106–554; H.R. 5658)), and our associated Information Quality Guidelines provide criteria, establish procedures, and provide guidance to ensure that our decisions are based on the best scientific data available. They require our biologists, to the extent consistent with the Act and with the use of the best scientific data available, to use primary and original sources of information as the basis for recommendations to designate critical habitat.

When we are determining which areas should be designated as critical habitat, our primary source of information is generally the information developed during the listing process for the species. Additional information sources may include the recovery plan for the species, articles in peer-reviewed journals, conservation plans developed by States and counties, scientific status surveys and studies, biological assessments, other unpublished materials, or experts' opinions or personal knowledge.

Habitat is dynamic, and species may move from one area to another over time. We recognize that critical habitat designated at a particular point in time may not include all of the habitat areas that we may later determine are necessary for the recovery of the species. For these reasons, a critical habitat designation does not signal that habitat outside the designated area is unimportant or may not be needed for recovery of the species. Areas that are important to the conservation of the species, both inside and outside the critical habitat designation, will continue to be subject to: (1) Conservation actions implemented under section 7(a)(1) of the Act, (2) regulatory protections afforded by the requirement in section 7(a)(2) of the Act for Federal agencies to insure their actions are not likely to jeopardize the continued existence of any endangered or threatened species, and (3) section 9 of the Act's prohibitions on taking any individual of the species, including taking caused by actions that affect habitat. Federally funded or permitted projects affecting listed species outside their designated critical habitat areas may still result in jeopardy findings in some cases. These protections and conservation tools will continue to contribute to recovery of this species. Similarly, critical habitat designations made on the basis of the best available information at the time of designation will not control the direction and substance of future recovery plans, habitat conservation plans (HCPs), or other species conservation planning efforts if new information available at the time of these planning efforts calls for a different outcome.

Physical or Biological Features

In accordance with section 3(5)(A)(i) and 4(b)(1)(A) of the Act and regulations at 50 CFR 424.12, in determining which areas within the geographical area occupied by the species at the time of listing to designate as critical habitat, we consider the physical or biological features essential to the conservation of the species and which may require special management considerations or protection. These include, but are not limited to:

(1) Space for individual and population growth and for normal behavior;

(2) Food, water, air, light, minerals, or other nutritional or physiological requirements;

(3) Cover or shelter;

(4) Sites for breeding, reproduction, or rearing (or development) of offspring; and

(5) Habitats that are protected from disturbance or are representative of the historical, geographical, and ecological distributions of a species.

We derived the specific physical or biological features essential for *Chromolaena frustrata* from studies of this species' habitat, ecology, and life history as described in the Critical Habitat section of the proposed rule to designate critical habitat published in the **Federal Register** on October 11, 2012 (77 FR 61836), and in the information presented below. We have determined that physical or biological features presented below are required for the conservation of *C. frustrata*. One change to these features in this final determination from the proposed rule is a result of the peer review process: coastal hardwood hammock has been added to the plant communities known for *C. frustrata* because it describes the plant community more accurately in ENP (Sadle 2012a, pers. comm.). We also include new information about reproductive patterns in the genus *Chromolaena*.

Space for Individual and Population Growth

Plant Community and Competitive Ability. *Chromolaena frustrata* occurs in communities classified as coastal berms, coastal rock barrens, buttonwood forests, coastal hardwood hammocks, and rockland hammocks restricted to tropical south Florida and the Florida

Keys. These communities and their associated native plant species are provided in the Status Assessment for *Chromolaena frustrata, Consolea corallicola,* and *Harrisia aboriginum* section of the proposed rule (77 FR 61836) and the newly added information on coastal hardwood hammocks and buttonwood forests in this final rule. Therefore, we identify upland habitats consisting of coastal berms, coastal rock barrens, buttonwood forests, coastal hardwood hammocks, and rockland hammocks restricted to tropical south Florida and the Florida Keys to be a physical or biological feature for *Chromolaena frustrata.*

Food, Water, Air, Light, Minerals, or Other Nutritional or Physiological Requirements

Climate (temperature and precipitation). The climate of south Florida where *Chromolaena frustrata* occurs is characterized by distinct wet and dry seasons, a monthly mean temperature above 64.4 °F (18 °C) in every month of the year, and annual rainfall averaging 30 to 60 in (75 to 150 cm) (Gabler *et al.* 1994, p. 211). Freezes can occur in the winter months, but are very infrequent at this latitude in Florida.

Soils. Substrates supporting *Chromolaena frustrata* for anchoring or nutrient absorption vary depending on the habitat and location and include marl (an unconsolidated sedimentary rock or soil consisting of clay and lime) (Sadle 2008 and 2012a, pers. comm.); soils consisting of covering limestone; exposed bare limestone rock or with a thin layer of leaf litter or highly organic soil (Bradley and Gann 1999, p. 37; FNAI 2010d, p. 1); or loose sediment formed by a mixture of coarse sand, shell fragments, pieces of coralline algae, and other coastal debris (FNAI 2010a, p. 1). The natural process giving rise to coastal rock barren is not known, but as it occurs on sites where the thin layer of organic soil over limestone bedrock is missing, coastal rock barren may have formed by soil erosion following destruction of the plant cover by fire or storm surge (FNAI 2010c, p. 2). Therefore, we identify substrates derived from calcareous sand, limestone, or marl that provide anchoring and nutritional requirements to be a physical or biological feature for *Chromolaena frustrata.*

Hydrology. The species requires coastal berms and coastal rock barrens habitats that occur above the daily tidal range, but are subject to flooding by seawater during extreme tides and storm surge. Rockland hammock and coastal hardwood hammock occur on high ground that does not regularly flood, but they are often dependent upon a high water table to keep humidity levels high, and they can be inundated during storm surges (FNAI 2010d, p. 1). Therefore, we identify habitats inundated by storm surge or tidal events at a frequency needed to limit plant species competition while not creating too high of a saline condition to be a physical or biological feature for *Chromolaena frustrata.*

Cover or Shelter

Chromolaena frustrata occurs in open canopy and semi-open to closed canopy habitats and thrives in areas of moderate sun exposure (Bradley and Gann 1999, p. 37). The amount and frequency of such microsites varies by habitat type and time elapsed since the last disturbance. In rockland and coastal hardwood hammocks, suitable microsites will often be found near the hammock edge where the canopy is most open. However, the species has been observed to spread into the hammocks when canopy cover is reduced by hurricane damage to canopy trees. More open communities (e.g., coastal berm, buttonwood, and salt marsh ecotone) provide more abundant and temporally consistent suitable habitat than communities capable of establishing a dense canopy (e.g., rockland and coastal hardwood hammock). Therefore, we identify habitats that have a vegetation composition and structure that allows for adequate sunlight and space for individual growth and population expansion to be a physical or biological feature for *Chromolaena frustrata.*

Sites for Breeding, Reproduction, or Rearing (or Development) of Offspring

While there have been no studies on the reproductive biology of *Chromolaena frustrata,* we can draw some generalizations from other species of *Chromolaena,* which reproduce sexually. Pollinators are likely to be generalists, such as butterflies, bees, flies, and beetles. New plants originate from seeds and seeds dispersal is largely by wind (Lakshmi *et al.* 2011, p. 1).

The sparsely vegetated edges or interior portions opened by canopy disruption are the areas of rockland and coastal hardwood hammock that have light levels sufficient to support *Chromolaena frustrata.* However, the dynamic nature of the habitat means that areas not currently open may become open in the future as a result of canopy disruption from hurricanes, while areas currently open may develop more dense canopy over time, eventually rendering that portion of the hammock unsuitable for *C. frustrata.* Therefore, we identify habitats that have disturbance regimes, including hurricanes, and infrequent inundation events that saturate the substrate and maintain the habitat suitability to be physical or biological features for *Chromolaena frustrata.*

Habitats Protected From Disturbance or Representative of the Historical, Geographic, and Ecological Distributions of the Species

Chromolaena frustrata continues to occur in habitats that are protected from human-generated disturbances and are representative of the species' historical, geographical, and ecological distribution although its range has been reduced. The species is still found in all of its representative plant communities: rock barrens, coastal berms, buttonwood forest, coastal hardwood hammocks, and rockland hammocks. In addition, representative communities are located on Federal, State, local, and private conservation lands that implement conservation measures benefitting the species. The species requires habitat of sufficient size and connectivity that can support species growth, distribution and population expansion.

Primary Constituent Elements for Chromolaena frustrata

Under the Act and its implementing regulations, we are required to identify the physical or biological features essential to the conservation of *Chromolaena frustrata* in areas occupied at the time of listing, focusing on the features' primary constituent elements (PCEs). Primary constituent elements are those specific elements of the physical or biological features that provide for a species' life-history processes and are essential to the conservation of the species.

Based on our current knowledge of the physical or biological features and habitat characteristics required to sustain the species' life-history processes, we determine that the PCEs specific to *Chromolaena frustrata* are:

(1) Areas of upland habitats consisting of coastal berm, coastal rock barren, coastal hardwood hammock, rockland hammocks, and buttonwood forest.

(a) Coastal berm habitat that contains:

(i) Open to semi-open canopy, subcanopy, and understory; and

(ii) Substrate of coarse, calcareous, storm-deposited sediment.

(b) Coastal rock barren (Keys cactus barren, Keys tidal rock barren) habitat that contains:

(i) Open to semi-open canopy and understory; and

(ii) Limestone rock substrate.

(c) Coastal hardwood hammock habitat occurring in Everglades National Park that contains:

(i) Canopy gaps and edges with an open to semi-open canopy, subcanopy, and understory; and

(ii) Substrate of marl covered with a thin layer of highly organic soil.

(d) Rockland hammock habitat that contains:

(i) Canopy gaps and edges with an open to semi-open canopy, subcanopy, and understory; and

(ii) Substrate with a thin layer of highly organic soil, marl, humus, or leaf litter on top of the underlying limestone.

(e) Buttonwood forest habitat that contains:

(i) Open to semi-open canopy and understory; and

(ii) Substrate with calcareous marl muds, calcareous sands, or limestone rock.

(2) Plant communities of predominately native vegetation with either no invasive, nonnative species or with low enough quantities of nonnative, invasive plant species to have minimal effect on the survival of *Chromolaena frustrata.*

(3) A disturbance regime, due to the effects of strong winds or saltwater inundation from storm surge or infrequent tidal inundation, that creates canopy openings in coastal berm, coastal rock barren, coastal hardwood hammock, rockland hammocks, and buttonwood forest.

(4) Habitats that are connected and of sufficient area to sustain viable populations in coastal berm, coastal rock barren, coastal hardwood hammock, rockland hammocks, and buttonwood forest.

Special Management Considerations or Protections

When designating critical habitat, we assess whether the specific areas within the geographical area occupied by the species at the time of listing contain features that are essential to the conservation of the species and which may require special management considerations or protection.

Special management considerations or protection are necessary throughout the critical habitat areas to avoid further degradation or destruction of the habitat that contains those features essential for the conservation of the species. The primary threats to the physical or biological features that *Chromolaena frustrata* depends on include: (1) Habitat destruction and modification by development; (2) competition with nonnative, invasive plant species that changes the habitat composition and structure; (3) wildfire that destroys habitat; (4) hurricanes and storm surge, if too frequent or severe destroy or modify habitat making it unsuitable; and (5) sea-level rise that changes the habitat to a more saline environment. Some of these threats can be addressed by special management considerations or protection while others (e.g., sea-level rise, hurricanes) are beyond the control of landowners and managers. However, while landowners or land managers may not be able to control all the threats, they may be able to address the results of the threats to the habitats.

Management activities that could ameliorate these threats include the monitoring and minimizing recreational activities impacts, nonnative species control, and protection from development. Precautions are needed to avoid the inadvertent trampling of *Chromolaena frustrata* in the course of management activities and public use. Development of recreation facilities or programs should avoid impacting these habitats directly or indirectly. Ditching and filling should be avoided because they alter the hydrology and species composition of these habitats. Sites that have shown increasing encroachment of woody species over time may require efforts to maintain the open nature of the habitat, which favors these species. Nonnative species control programs are needed to reduce competition and prevent habitat degradation. The reduction of these threats will require the implementation of special management actions within each of the critical habitat areas identified in this rule. All critical habitat requires active management to address the ongoing threats listed.

In summary, we find that each of the areas we are designating as critical habitat contain features essential to the conservation of *Chromolaena frustrata* that may require special management considerations or protection to ensure conservation of the species. These special management considerations and protections are required to preserve and maintain the essential features provided to *C. frustrata* by the ecosystems upon which it depends. A more detailed discussion of these threats is presented in the proposed rule under ''Summary of Factors Affecting the Species'' (77 FR 61836; October 11, 2012).

Criteria Used To Identify Critical Habitat

As required by section 4(b)(2) of the Act, we used the best scientific data available to designate critical habitat. In accordance with the Act and our implementing regulations at 50 CFR 424.12(b) we review available information pertaining to the habitat requirements of the species and identify occupied areas at the time of listing that contain the features essential to the conservation of the species. If after identifying currently occupied areas, we determine that those areas are inadequate to ensure conservation of the species, in accordance with the Act and our implementing regulations at 50 CFR 424.12(e), we then consider whether designating additional areas—outside those currently occupied—are essential for the conservation of the species. In this rule, we are designating critical habitat in areas within the geographical area occupied by the species at the time of listing in 2013. We also are designating specific areas outside the geographical area occupied by the species at the time of listing that were historically occupied, because we have determined that such areas are essential for the conservation of the species. Sources of data for this analysis included the following:

(1) Florida Natural Areas Inventory (FNAI) population records and ArcGIS geographic information system (GIS) software to spatially depict the location and extent of documented populations of *Chromolaena frustrata* (FNAI 2012, pp. 1–17);

(2) Reports prepared by botanists with the Institute for Regional Conservation (IRC), National Park Service (NPS), and Florida Department Environmental Protection (FDEP). Some of these were funded by the Service, others were requested or volunteered by biologists with the NPS or FDEP;

(3) Historical records found in reports and associated voucher specimens housed at herbaria, all of which are also referenced in the above mentioned reports from the IRC and FNAI;

(4) Digitally produced habitat maps provided by NPS and Monroe County; and

(5) Aerial images of Miami-Dade and Monroe Counties. The presence of PCEs was determined through the use of GIS spatial data depicting the current habitat status. This habitat data for the Florida Keys were developed by Monroe County from 2006 aerial images, and ground conditions for many areas were checked in 2009. Habitat data for ENP were provided by the NPS. The areas that contain PCEs follow predictable landscape patterns and have a recognizable signature in the aerial photographs.

Four of the eight extant *Chromolaena frustrata* populations consist of fewer than 100 individuals; two others have fewer than 250 individuals. Small populations such as these populations that have limited distributions, are

vulnerable to relatively minor environmental disturbances (Given 1994, pp. 66–76; Frankham 2005, pp. 135–136), and are subject to the loss of genetic diversity from genetic drift, the random loss of genes, and inbreeding (Ellstrand and Elam 1993, pp. 217–237; Leimu *et al.* 2006, pp. 942–952). Plant populations with lowered genetic diversity are more prone to local extinction (Barrett and Kohn 1991, pp. 4, 28). Smaller plant populations generally have lower genetic diversity, and lower genetic diversity may in turn lead to even smaller populations by decreasing the species' ability to adapt, thereby increasing the probability of population extinction (Newman and Pilson 1997, p. 360; Palstra and Ruzzante 2008, pp. 3428–3447). Because of the risks associated with small populations or limited distributions, the recovery of many rare plant species includes the creation of new sites or reintroductions to ameliorate these effects.

The current distribution of the *Chromolaena frustrata* is much reduced from its historical distribution. We anticipate that recovery will require continued protection of existing populations and habitat, as well as establishing populations in additional locations that more closely approximate its historical distribution in order to ensure there is adequate number of *C. frustrata* stable populations and that these populations occur over a wide geographic area within the species' historical range. This will help to ensure that catastrophic events, such as hurricanes or wildfire, would not simultaneously affect all known populations.

Areas Occupied at the Time of Listing

For the purpose of designating critical habitat for *Chromolaena frustrata,* we defined the geographical area currently occupied by the species as required by section 3(5)(A)(i) of the Act. The occupied critical habitat units were delineated around documented extant populations. These units include the mapped extent of the population that contain one or more of the elements of the physical or biological features. We considered the following when identifying occupied areas of critical habitat:

(1) Space to allow for the successional nature of the occupied habitats (i.e., gain and loss of areas with sufficient light availability due to disturbance of the tree canopy driven by natural events such as inundation and hurricanes), and habitat transition or loss due to sea-level rise. In ENP, the distribution of *Chromolaena frustrata* is across a larger area than at any other single location. In the Florida Keys, the same criteria were used, but the size of the units is limited by the size of individual islands.

(2) Some areas will require special management to maintain connectivity of occupied habitat to allow for population expansion and connection with other populations. Isolation of populations can result in localized extinctions.

(3) Some areas will require special management to be able to support a higher density of the plant within the occupied space. These areas generally are habitats where some of the primary constituent elements have been lost through natural or human causes. These areas would help to off-set the anticipated loss and degradation of habitat occurring or expected from the effects of climate change (such as sea-level rise) or due to development.

After following the above criteria, we determined that occupied areas were not sufficient for the conservation of the species for the following reasons: (1) Restoring the species to its historical range and reducing its vulnerability to stochastic events such as hurricanes and storm surge requires reintroduction to areas where it occurred in the past but has since been extirpated; (2) providing increased connectivity for populations and areas for small populations to expand requires currently unoccupied habitat; and (3) reintroduction or assisted migration to reduce the vulnerability of the species to sea-level rise and storm surge requires higher elevation sites that currently are unoccupied by *Chromolaena frustrata.* Therefore, we looked to unoccupied areas that may be essential for the conservation of the species.

Areas Outside the Geographic Area Occupied at the Time of Listing

When designating critical habitat, we consider future recovery efforts and conservation of the species. Realizing that the current occupied habitat is not enough for the conservation and recovery of *Chromolaena frustrata,* we used habitat and historical occurrence data to identify unoccupied habitat essential for the conservation of the species as described below.

The unoccupied areas are essential for the conservation of the species because they:

(1) Represent the historical range of *Chromolaena frustrata. C. frustrata* has been extirpated from several locations where it was previously recorded. Of those areas found in reports, we are designating critical habitat only where there are well documented historical occurrences (i.e., Big Pine Key and Key Largo (Bradley and Gann 2004, pp. 4–6)). These areas still retain some or all the elements of the physical or biological features. Areas such as Fiesta Key and Knight's Key, which once supported populations of *C. frustrata* but no longer contain any PCEs and cannot be restored, are not included.

(2) Provide areas of sufficient size to support ecosystem processes for populations of *Chromolaena frustrata.* These areas are essential for the conservation of the species because they will provide areas for population expansion and growth. Large contiguous parcels of habitat are more likely to be resilient to ecological processes of disturbance and succession, and support viable populations of *C. frustrata.* The unoccupied areas selected were at least 30 ac (12.1 ha) or greater in size.

The amount and distribution of designated critical habitat will allow *Chromoleana frustrata* to:

(1) Maintain its existing distribution;

(2) Expand its distribution into historically occupied areas (needed to offset habitat loss and fragmentation);

(3) Use habitat depending on habitat availability (respond to changing nature of coastal habitat including occurring sea-level rise) and support genetic diversity;

(4) Increase the size of each population to a level where the threats of genetic, demographic, and normal environmental uncertainties are diminished; and

(5) Maintain its ability to withstand local or unit level environmental fluctuations or catastrophes.

When determining critical habitat boundaries within this final rule, we made every effort to avoid including developed areas such as lands covered by buildings, pavement, and other structures because such lands lack physical or biological features for *Chromolaena frustrata.* The scale of the maps we prepared under the parameters for publication within the Code of Federal Regulations may not reflect the exclusion of such developed lands. Any such lands inadvertently left inside critical habitat boundaries shown on the maps of this final rule have been excluded by text in the rule and are not designated as critical habitat. Therefore, a Federal action involving these lands will not trigger section 7 consultation with respect to critical habitat and the requirement of no adverse modification unless the specific action would affect the physical or biological features in the adjacent critical habitat.

The critical habitat designation is defined by the map or maps, as modified by any accompanying regulatory text, presented at the end of

this document in the Regulation Promulgation section. We include more detailed information on the boundaries of the critical habitat designation in the preamble of this document. We will make the coordinates or plot points or both on which each map is based available to the public on *http://www.regulations.gov* at Docket No. FWS–R4–ES–2013–0029, on our Internet site at *http://www.fws.gov/verobeach/,* and at the field office responsible for the designation (see **FOR FURTHER INFORMATION CONTACT**, above).

Final Critical Habitat Designation

We are designating nine units as critical habitat for *Chromolaena frustrata.* The critical habitat areas described below constitute our best assessment at this time of areas that meet the definition of critical habitat for *C. frustrata.* The nine units are: (1) Everglades National Park (ENP); (2) Key Largo; (3) Upper Matecumbe Key; (4) Lignumvitae Key; (5) Lower Matecumbe Key; (6) Long Key; (7) Big Pine Key; (8) Big Munson Island; and (9) Boca Grande Key. Land ownership within the critical habitat consists of Federal (70 percent), State (23 percent), and private and other (6 percent). Table 1 summarizes these units.

TABLE 1—*Chromolaena frustrata* CRITICAL HABITAT UNITS

Unit No.	Unit Name	Ownership	Percent	Acres	Hectares	Occupied
1	Everglades National Park	Federal	100	6,166	2,495	yes.
		Total	*100*	*6,166*	*2,495*	
2	Key Largo	Federal	23	804	325	no.
		State	63	2,170	878	
		Private	13	457	185	
		Total	*100*	*3,431*	*1,388*	
3	Upper Matecumbe Key	State	34	24	10	yes.
		Private	66	45	18	
		Total	*100*	*69*	*28*	
4	Lignumvitae Key	State	100	180	73	yes.
		Total	*100*	*180*	*73*	
5	Lower Matecumbe Key	State	49	22	9	yes.
		Private	51	22	9	
		Total	*100*	*44*	*18*	
6	Long Key	State	73	151	61	yes.
		Private	27	57	23	
		Total	*100*	*208*	*84*	
7	Big Pine Key	Federal	88	686	278	no.
		Private	12	94	38	
		Total	*100*	*780*	*316*	
8	Big Munson Island	Private	100	28	11	yes.
		Total	*100*	*28*	*11*	
9	Boca Grande Key	Federal	100	62	25	yes.
		Total	*100*	*62*	*25*	
Total All Units		Federal	70	7,718	3,123	
		State	23	2,547	1,031	
		Private and Other	6	703	284	
		All		10,968	4,439	

Note: Area sizes may not sum due to rounding.

We present brief descriptions of all units, and reasons why they meet the definition of critical habitat for *Chromolaena frustrata,* below.

Unit 1: Everglades National Park, Monroe County and Miami-Dade County

Unit 1 consists of a total of 6,166 ac (2,495 ha) in Monroe and Miami-Dade Counties. This unit is composed entirely of lands in Federal ownership, 100 percent of which are located within the Everglades National Park along the southern coast of Florida from Cape Sable to Trout Cove, located between the mean high water line to approximately 2.5 mi (4.02 km) inland. This unit is currently occupied and contains all the physical or biological features required by the species. The unit contains coastal hardwood hammock and buttonwood forest primary constituent elements. The physical or biological features in this unit may require special management considerations or protection to address threats of nonnative plant species and sea-level rise. The National Park Service conducts nonnative species control and monitors *Chromolaena frustrata* occurrences in ENP.

Unit 2: Key Largo, Monroe County

Unit 2 consists of a total of 3,431 ac (1,388 ha) in Monroe County. This unit is composed of Federal lands within Crocodile Lake National Wildlife Refuge (NWR) (804 ac (325 ha)); State lands within Dagny Johnson Botanical State Park, John Pennekamp Coral Reef State Park, and the Florida Keys Wildlife and Environmental Area (2,170 ac (878 ha)); and parcels in private ownership (457 ac (185 ha)).

This unit extends from near the northern tip of Key Largo, along the length of Key Largo, beginning at the south shore of Ocean Reef Harbor near South Marina Drive and the intersection of County Road (CR) 905 and Clubhouse Road on the west side of CR 905, and between CR 905 and Old State Road 905, then extending to the shoreline south of South Harbor Drive. The unit then continues on both sides of CR 905 through the Crocodile Lake NWR, Dagny Johnson Key Largo Hammock Botanical State Park, and John Pennekamp Coral Reef State Park. The unit then terminates near the junction of U.S. 1 and CR 905 and Garden Cove Drive. The unit resumes on the east side of U.S. 1 from South Andros Road to Key Largo Elementary School; then from intersection of Taylor Drive and Pamela

Street to Avenue A; then from Sound Drive to the intersection of Old Road and Valencia Road; then resumes on the east side of U.S. 1 from Hibiscus Lane and Ocean Drive. The unit continues south near the Port Largo Airport from Poisonwood Road to Bo Peep Boulevard. The unit resumes on the west side of U.S. 1 from the intersection of South Drive and Meridian Avenue to Casa Court Drive. The unit then continues on the west side of U.S. 1 from the point on the coast directly west of Peace Avenue south to Caribbean Avenue. The unit also includes a portion of El Radabob Key.

This unit is not currently occupied but is essential for the conservation of the species because it serves to protect habitat needed to recover the species, reestablish wild populations within the historical range of the species, and maintain populations throughout the historical distribution of the species in the Florida Keys. It also provides area for recovery in the case of stochastic events that otherwise would eliminate the species from the one or more locations it is presently found. The Service conducts nonnative species control efforts at Crocodile Lake NWR, and FDACS conducts nonnative species control efforts at Dagny Johnson Botanical State Park, John Pennekamp Coral Reef State Park, and the Florida Keys Wildlife and Environmental Area.

Unit 3: Upper Matecumbe Key, Monroe County

Unit 3 consists of a total of 69 ac (28 ha) in Monroe County. This unit is composed of State lands within Lignumvitae Key State Botanical Park, Indian Key Historical State Park (24 ac (10 ha)); City of Islamorada lands within the Key Tree Cactus Preserve and Green Turtle Hammock Park and parcels in private ownership (45 ac (18 ha)).

This unit extends from Matecumbe Avenue south to Seashore Avenue along either side of U.S. 1. The unit then continues along the west side of U.S. 1, including the Green Turtle Hammock Park and a nature preserve owned by the City of Islamorada; straddles U.S. 1 in the vicinity of Indian Key Historical Park; and continues for 0.5 mi (0.8 km) to near the southern tip of Key Largo on the west side of U.S. 1. This unit is currently occupied and contains all the physical or biological features essential for the conservation of the species. It contains the primary constituent elements of coastal berm, coastal rock barren, and rockland hammock.

The physical or biological features in this unit may require special management considerations or protection to address threats of small population size, nonnative species, and sea-level rise. FDACS conducts nonnative species control efforts in Lignumvitae Key State Botanical Park and Indian Key Historical State Park.

Unit 4: Lignumvitae Key, Monroe County

Unit 4 consists of a total of 180 ac (73 ha) in Monroe County. This unit is composed entirely of lands in State ownership, 100 percent of which are located within the Lignumvitae Key Botanical State Park (LKBSP) on Lignumvitae Key in the Florida Keys. This unit includes the entire upland area of Lignumvitae Key.

This unit is currently occupied and contains all the physical or biological features essential for the conservation of the species. This unit includes all the primary constituent of rockland hammock and buttonwood forest habitat that occur within LKBSP on Lignumvitae Key. The physical or biological features in this unit may require special management considerations or protection to address threats of small population size, nonnative species, and sea-level rise. FDACS conducts nonnative species control efforts at LKBSP.

Unit 5: Lower Matecumbe Key, Monroe County

Unit 5 consists of a total of 44 ac (18 ha) in Monroe County. The unit is composed of State lands within Lignumvitae Key Botanical State Park and parcels owned by the Florida Department of Transportation (22 ac (9 ha)); and parcels in private ownership (22 ac (9 ha)). This unit extends from the east side of U.S. 1 from 0.14 mi (0.2 km) from the north edge of Lower Matecumbe Key, situated across U.S. 1 from Davis Lane and Tiki Lane. The unit continues on either side of U.S. 1 approximately 0.4 mi (0.6 km) from the north edge of Lower Matecumbe Key for approximately 0.6 mi (0.9 km).

This unit is currently occupied and contains all the physical or biological features essential for the conservation of the species. The physical or biological features in this unit may require special management considerations or protection to address threats of small population size, nonnative species, and sea-level rise. FDACS conducts nonnative species control efforts at Lignumvitae Key Botanical State Park.

Unit 6: Long Key, Monroe County

Unit 6 consists of a total of 208 ac (84 ha) in Monroe County. This unit is composed of State lands within Long Key State Park (151 ac (61 ha)) and parcels in private ownership (57 ac (23 ha)). The unit extends from the southwestern tip of Long Key along the island's west and south shores.

The unit is currently occupied and contains all the physical or biological features essential to the conservation of the species. It contains the PCEs of coastal berm, coastal rock barren, rockland hammock, and buttonwood forest. The physical or biological features in this unit may require special management considerations or protection to address threats of development, small population size, nonnative species, and sea-level rise. FDACS conducts nonnative species control efforts at Long Key State Park.

Unit 7: Big Pine Key, Monroe County

Unit 7 consists of a total of 780 ac (316 ha) in Monroe County. This unit is composed of Federal land within the National Key Deer Refuge (NKDR) (686 ac (278 ha)) and parcels in private ownership (94 ac (38 ha)). This unit extends from near the northern tip of Big Pine Key along the eastern shore to the vicinity of Hellenga Drive and Watson Road; from Gulf Boulevard south to West Shore Drive; extending from the southwest tip of Big Pine Key, bordered by Big Pine Avenue and Elma Avenues on the east, Coral and Yacht Club Road, and U.S. 1 on the north, and Industrial Avenue on the east; along Long Beach Drive; and from the southeastern tip of Big Pine Key to Avenue A.

This unit is not currently occupied but is essential for the conservation of the species because it serves to protect habitat needed to recover the species, reestablish wild populations within the historical range of the species, and maintain populations throughout the historical distribution of the species in the Florida Keys. It also provides area for recovery in the case of stochastic events that otherwise hold the potential to eliminate the species from the one or more locations where it is presently found. The Service conducts nonnative species control at the National Key Deer Refuge.

Unit 8: Big Munson Island, Monroe County

Unit 8 consists of a total of 28 ac (11 ha) in Monroe County. This unit is composed entirely of lands in private ownership, owned by the Boy Scouts of America. This unit is occupied and contains all the physical or biological features essential for the conservation of the species. It includes all the PCEs of coastal berm, rockland hammock, and buttonwood forest habitat that occur on Big Munson Island.

The physical or biological features in this unit may require special management considerations or protection to address threats of development, recreation, nonnative species, and sea-level rise. No conservation actions are known.

Unit 9: Boca Grande Key, Monroe County

Unit 9 consists of a total of 62 ac (25 ha) in Monroe County. This unit is composed entirely of lands in Federal ownership, 100 percent of which is located within the Key West National Wildlife Refuge. This unit is occupied and contains all the physical or biological features essential for the conservation of the species. This unit includes all the primary constituent elements of coastal berm, rockland hammock, and buttonwood forest habitat on the island, comprising the entirety of Boca Grande Key.

The physical or biological features in this unit may require special management considerations or protection to address threats of small population size, nonnative species, and sea-level rise. The Service conducts nonnative species control at the Key West Refuge.

Unit 9 of the critical habitat units for *Chromolaena frustrata* is currently designated as critical habitat under the Act for the wintering piping plover (*Charadrius melodus,* 50 CFR 17.95(b)), and Units 1, 2, 3, 4, 5, and 6 are designated for the American crocodile (*Crocodylus acutus,* 50 CFR 17.95(c)).

Effects of Critical Habitat Designation

Section 7 Consultation

Section 7(a)(2) of the Act requires Federal agencies, including the Service, to ensure that any action they fund, authorize, or carry out is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of designated critical habitat of such species. In addition, section 7(a)(4) of the Act requires Federal agencies to confer with the Service on any agency action which is likely to jeopardize the continued existence of any species proposed to be listed under the Act or result in the destruction or adverse modification of proposed critical habitat.

Decisions by the 5th and 9th Circuit Courts of Appeals have invalidated our regulatory definition of ''destruction or adverse modification'' (50 CFR 402.02) (see *Gifford Pinchot Task Force* v. *U.S. Fish and Wildlife Service,* 378 F. 3d 1059 (9th Cir. 2004) and *Sierra Club* v. *U.S. Fish and Wildlife Service et al.,* 245 F.3d 434 (5th Cir. 2001)), and we do not rely on this regulatory definition when analyzing whether an action is likely to destroy or adversely modify critical habitat. Under the provisions of the Act, we determine destruction or adverse modification on the basis of whether, with implementation of the proposed Federal action, the affected critical habitat would continue to serve its intended conservation role for the species.

If a Federal action may affect a listed species or its critical habitat, the responsible Federal agency (action agency) must enter into consultation with us. Examples of actions that are subject to the section 7 consultation process are actions on State, tribal, local, or private lands that require a Federal permit (such as a permit from the U.S. Army Corps of Engineers under section 404 of the Clean Water Act (33 U.S.C. 1251 *et seq.*) or a permit from the Service under section 10 of the Act) or that involve some other Federal action (such as funding from the Federal Highway Administration, Federal Aviation Administration, or the Federal Emergency Management Agency). Federal actions not affecting listed species or critical habitat, and actions on State, tribal, local, or private lands that are not federally funded or authorized, do not require section 7 consultation.

As a result of section 7 consultation, we document compliance with the requirements of section 7(a)(2) through our issuance of:

(1) A concurrence letter for Federal actions that may affect, but are not likely to adversely affect, listed species or critical habitat; or

(2) A biological opinion for Federal actions that may affect and are likely to adversely affect, listed species or critical habitat.

When we issue a biological opinion concluding that a project is likely to jeopardize the continued existence of a listed species and/or destroy or adversely modify critical habitat, we provide reasonable and prudent alternatives to the project, if any are identifiable, that would avoid the likelihood of jeopardy and/or destruction or adverse modification of critical habitat. We define ''reasonable and prudent alternatives'' (at 50 CFR 402.02) as alternative actions identified during consultation that:

(1) Can be implemented in a manner consistent with the intended purpose of the action,

(2) Can be implemented consistent with the scope of the Federal agency's legal authority and jurisdiction,

(3) Are economically and technologically feasible, and

(4) Would, in the Director's opinion, avoid the likelihood of jeopardizing the continued existence of the listed species and/or avoid the likelihood of destroying or adversely modifying critical habitat.

Reasonable and prudent alternatives can vary from slight project modifications to extensive redesign or relocation of the project. Costs associated with implementing a reasonable and prudent alternative are similarly variable.

Regulations at 50 CFR 402.16 require Federal agencies to reinitiate consultation on previously reviewed actions in instances where we have listed a new species or subsequently designated critical habitat that may be affected and the Federal agency has retained discretionary involvement or control over the action (or the agency's discretionary involvement or control is authorized by law). Consequently, Federal agencies sometimes may need to request reinitiation of consultation with us on actions for which formal consultation has been completed, if those actions with discretionary involvement or control may affect subsequently listed species or designated critical habitat.

Application of the ''Adverse Modification'' Standard

The key factor related to the adverse modification determination is whether, with implementation of the proposed Federal action, the affected critical habitat would continue to serve its intended conservation role for the species. Activities that may destroy or adversely modify critical habitat are those that alter the physical or biological features to an extent that appreciably reduces the conservation value of critical habitat for *Chromolaena frustrata.* As discussed above, the role of critical habitat is to support life-history needs of the species and provide for the conservation of the species.

Section 4(b)(8) of the Act requires us to briefly evaluate and describe, in any proposed or final regulation that designates critical habitat, activities involving a Federal action that may destroy or adversely modify such habitat, or that may be affected by such designation.

Activities that may affect critical habitat, when carried out, funded, or authorized by a Federal agency, should result in consultation for *Chromolaena frustrata.* These activities include, but are not limited to:

(1) Actions that would significantly alter the hydrology or substrate, such as

ditching or filling. Such activities may include, but are not limited to, road construction or maintenance, and residential, commercial, or recreational development.

(2) Actions that would significantly alter vegetation structure or composition, such as clearing vegetation for construction of residences, facilities, trails, and roads.

(3) Actions that would introduce nonnative species that would significantly alter vegetation structure or composition. Such activities may include, but are not limited to, residential and commercial development, and road construction.

Exemptions

Application of Section 4(a)(3) of the Act

Section 4(a)(3)(B)(i) of the Act (16 U.S.C. 1533(a)(3)(B)(i)) provides that: ''The Secretary shall not designate as critical habitat any lands or other geographic areas owned or controlled by the Department of Defense, or designated for its use, that are subject to an integrated natural resources management plan (INRMP) prepared under section 101 of the Sikes Act (16 U.S.C. 670a), if the Secretary determines in writing that such plan provides a benefit to the species for which critical habitat is proposed for designation.'' There are no Department of Defense lands with a completed INRMP within the proposed critical habitat designation. Therefore, we are not exempting any lands from this final designation of critical habitat for *Chromolaena frustrata* pursuant to section 4(a)(3)(B)(i) of the Act.

Exclusions

Application of Section 4(b)(2) of the Act

Section 4(b)(2) of the Act states that the Secretary shall designate and make revisions to critical habitat on the basis of the best available scientific data after taking into consideration the economic impact, national security impact, and any other relevant impact of specifying any particular area as critical habitat. The Secretary may exclude an area from critical habitat if she determines that the benefits of such exclusion outweigh the benefits of specifying such area as part of the critical habitat, unless she determines, based on the best scientific data available, that the failure to designate such area as critical habitat will result in the extinction of the species. In making that determination, the statute on its face, as well as the legislative history, is clear that the Secretary has broad discretion regarding which factor(s) to use and how much weight to give to any factor.

Under section 4(b)(2) of the Act, the Secretary may exclude an area from designated critical habitat based on economic impacts, impacts on national security, or any other relevant impacts. In considering whether to exclude a particular area from the designation, we identify the benefits of including the area in the designation, identify the benefits of excluding the area from the designation, and evaluate whether the benefits of exclusion outweigh the benefits of inclusion. If the analysis indicates that the benefits of exclusion outweigh the benefits of inclusion, the Secretary may exercise her discretion to exclude the area only if such exclusion would not result in the extinction of the species.

Exclusions Based on Economic Impacts

Under section 4(b)(2) of the Act, we consider the economic impacts of specifying any particular area as critical habitat. In order to consider economic impacts, we prepared a draft economic analysis of the proposed critical habitat designation and related factors (Loomis *et al.* 2013a, entire). The draft analysis, dated April 2013, was made available for public review from July 8, 2013, through August 7, 2013 (78 FR 40669). Following the close of the comment period, a final analysis of the potential economic effects of the proposed designation was developed taking into consideration the public comments and any new information (Loomis *et al.* 2013b, entire).

The intent of the final economic analysis (FEA) is to quantify the economic impacts of all potential conservation efforts for *Chromolaena frustrata;* some of these costs will likely be incurred regardless of whether we designate critical habitat (baseline). The economic impact of the critical habitat designation is analyzed by comparing scenarios both ''with critical habitat'' and ''without critical habitat.'' The ''without critical habitat'' scenario represents the baseline for the analysis, considering protections already in place for the species (e.g., under the Federal listing and other Federal, State, and local regulations). The baseline, therefore, represents the costs 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 are those not expected to occur absent 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 consider in the final designation of critical habitat. The analysis looks retrospectively at baseline impacts incurred since the species was listed, and forecasts both baseline and incremental impacts likely to occur with the designation of critical habitat.

The FEA also addresses how potential economic impacts are likely to be distributed, including an assessment of any local or regional impacts of habitat conservation and the potential effects of conservation activities on government agencies, private businesses, and individuals. The FEA measures lost economic efficiency associated with residential and commercial development and public projects and activities, such as economic impacts on water management and transportation projects, Federal lands, small entities, and the energy industry. Decision-makers can use this information to assess whether the effects of the designation might unduly burden a particular group or economic sector. Finally, the FEA looks retrospectively at costs that occurred between the publication of the final listing rule and the final rule designating critical habitat, and considers those costs that may occur in the 20 years following the designation of critical habitat, which was determined to be the appropriate period for analysis because limited planning information was available for most activities to forecast activity levels for projects beyond a 20-year timeframe. The FEA quantifies economic impacts of *Chromolaena frustrata* conservation efforts associated with the following categories of activity: (1) Commercial, residential and recreational development; (2) Federal land management; and (3) restoration and conservation.

Based on the best available information, including extensive discussions with stakeholders, we estimate the critical habitat designation will result in direct incremental costs of approximately between $578,000 (at a 7 percent discount rate), $764,000 (at a 3 percent discount rate), and $982,000 (not discounted) over the next 20 years, or $38,000 to $49,000 on an annual basis depending on the discount rate. We estimate 93 percent of the costs are attributable to Federal land management and restoration and conservation activities, and the remaining costs are attributable to with development in the area. The majority of these costs is administrative and is borne by Federal and State agencies; however, some costs may be incurred by local governments and businesses. These costs stem from

the requirement for Federal agencies to consult with the Service regarding the impacts of their actions, or those that they fund or authorize, on critical habitat.

Our economic analysis did not identify any disproportionate costs that are likely to result from the designation. Consequently, the Secretary is not exercising her discretion to exclude any areas from this designation of critical habitat for *Chromolaena frustrata* based on economic impacts.

A copy of the FEA with supporting documents may be obtained by contacting the South Florida Ecological Services Office (see **ADDRESSES**) or by downloading from the Internet at *http://www.regulations.gov.*

Exclusions Based on National Security Impacts

Under section 4(b)(2) of the Act, we consider whether there are lands owned or managed by the Department of Defense where a national security impact might exist. In preparing this final rule, we have determined that no lands within the designation of critical habitat for *Chromolaena frustrata* are owned or managed by the Department of Defense, and, therefore, we anticipate no impact on national security. Consequently, the Secretary is not exerting her discretion to exclude any areas from this final designation based on impacts on national security.

Exclusions Based on Other Relevant Impacts

Under section 4(b)(2) of the Act, we consider any other relevant impacts, in addition to economic impacts and impacts on national security. We consider a number of factors, including whether the landowners have developed any HCPs or other management plans for the area, or whether there are conservation partnerships that would be encouraged by designation of, or exclusion from, critical habitat. In addition, we look at any tribal issues, and consider the government-to-government relationship of the United States with tribal entities. We also consider any social impacts that might occur because of the designation.

In preparing this final rule, we have determined that there are currently no HCPs or other management plans for *Chromolaena frustrata,* and the final designation does not include any tribal lands or trust resources. We anticipate no impact on tribal lands, partnerships, or HCPs from this critical habitat designation. Accordingly, the Secretary is not exercising her discretion to exclude any areas from this final designation based on other relevant impacts.

Required Determinations

Regulatory Planning and Review (Executive Orders 12866 and 13563)

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

Executive Order 13563 reaffirms the principles of E.O. 12866 while calling for improvements in the nation's regulatory system to promote predictability, to reduce uncertainty, and to use the best, most innovative, and least burdensome tools for achieving regulatory ends. The executive order directs agencies to consider regulatory approaches that reduce burdens and maintain flexibility and freedom of choice for the public where these approaches are relevant, feasible, and consistent with regulatory objectives. E.O. 13563 emphasizes further that regulations must be based on the best available science and that the rulemaking process must allow for public participation and an open exchange of ideas. We have developed this rule in a manner consistent with these requirements.

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 (SBREFA) of 1996 (5 U.S.C. 801 *et seq.*), whenever an agency must 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 (small businesses, small organizations, and small government jurisdictions). However, no regulatory flexibility analysis is required if the head of an 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. In this final rule, we are certifying that the critical habitat designation for *Chromolaena frustrata* will not have a significant economic impact on a substantial number of small entities. The following discussion explains our rationale.

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; as well as small businesses. 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 on these small entities are significant, we consider the types of activities that might trigger regulatory impacts under this rule, as well as the 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.

Importantly, the incremental impacts of a rule must be *both* significant and substantial to prevent certification of the rule under the RFA and to require the preparation of a regulatory flexibility analysis. If a substantial number of small entities are affected by the critical habitat designation, but the per-entity economic impact is not significant, the Service may certify. Likewise, if the per-entity economic impact is likely to be significant, but the number of affected entities is not substantial, the Service may also certify.

The Service's current understanding of recent case law is that Federal agencies are only required to evaluate the potential impacts of rulemaking on those entities directly regulated by the rulemaking; therefore, they are not required to evaluate the potential impacts to those entities not directly regulated. The designation of critical habitat for an endangered or threatened species only has a regulatory effect where a Federal action agency is involved in a particular action that may affect the designated critical habitat. Under these circumstances, only the Federal action agency is directly regulated by the designation, and, therefore, consistent with the Service's current interpretation of RFA and recent case law, the Service may limit its evaluation of the potential impacts to those identified for Federal action agencies. Under this interpretation, there is no requirement under the RFA

to evaluate the potential impacts to entities not directly regulated, such as small businesses. However, Executive Orders 12866 and 13563 direct Federal agencies to assess costs and benefits of available regulatory alternatives in quantitative (to the extent feasible) and qualitative terms. Consequently, it is the current practice of the Service to assess to the extent practicable these potential impacts if sufficient data are available, whether or not this analysis is believed by the Service to be strictly required by the RFA. In other words, while the effects analysis required under the RFA is limited to entities directly regulated by the rulemaking, the effects analysis under the Act, consistent with the E.O.s' regulatory analysis requirements, can take into consideration impacts to both directly and indirectly impacted entities, where practicable and reasonable.

In conclusion, we believe that, based on our interpretation of directly regulated entities under the RFA and relevant case law, this designation of critical habitat will only directly regulate Federal agencies, which are not by definition small business entities. Accordingly, we certify that this designation of critical habitat will not have a significant economic impact on a substantial number of small business entities. Therefore, a regulatory flexibility analysis is not required. However, in our final economic analysis for this rule, we considered and evaluated the potential effects to third parties that may be involved with consultations with Federal action agencies related to this action.

Designation of critical habitat only affects activities authorized, funded, or carried out by Federal agencies. Some kinds of activities are unlikely to have any Federal involvement and so will not be affected by critical habitat designation. In areas where the species is present, Federal agencies already are required to consult with us under section 7 of the Act on activities they authorize, fund, or carry out that may affect the *Chromolaena frustrata.* Federal agencies also must consult with us if their activities may affect critical habitat. Designation of critical habitat, therefore, could result in an additional economic impact on small entities due to the requirement to reinitiate consultation for ongoing Federal activities (see *Application of the ''Adverse Modification'' Standard* section).

In our FEA, we evaluated the potential economic effects on small business entities resulting from conservation actions related to the listing of the *Chromolaena frustrata* and the designation of critical habitat. The analysis is based on the estimated impacts associated with the rulemaking as described in Chapters 4 through 5 and Appendices A and B of the analysis and evaluates the potential for economic impacts related to: (1) Federal land management; (2) commercial, residential, and recreational development; and (3) restoration and conservation.

The threshold for a small governmental jurisdiction is a city, county, town, school district, or special district with a population of less than 50,000. The village of Islamorada, which manages conservation areas within the Upper Matecumbe Key habitat unit, qualifies as a small entity under this definition. Based on communication with the village of Islamorada (2013), current management of these areas, including control of invasive species, is consistent with management expected following the listing and designation of critical habitat for *Chromolaena frustrata.* No incremental impacts are expected to the village of Islamorada.

There is the potential that project proponents for commercial, residential, and recreational development could be small businesses. As discussed in section 4.2 of the FEA, we do not estimate any incremental administrative time or project modifications above existing permitting requirements and restrictions on land clearing associated with development.

In summary, we considered whether this designation will result in a significant economic effect on a substantial number of small entities. Based on the above reasoning and currently available information, we concluded that this rule will not result in a significant economic impact on a substantial number of small entities. Therefore, we are certifying that the designation of critical habitat for *Chromolaena frustrata* will not have a significant economic impact on a substantial number of small entities, and a regulatory flexibility analysis is not required.

Energy Supply, Distribution, or Use—Executive Order 13211

Executive Order 13211 (Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use) requires agencies to prepare Statements of Energy Effects when undertaking certain actions. OMB has provided guidance for implementing this Executive Order that outlines nine outcomes that may constitute ''a significant adverse effect'' when compared to not taking the regulatory action under consideration.

Appendix A of the economic analysis discusses the potential for critical habitat to affect energy supply, distribution, or use through the additional cost of considering adverse modification in section 7 consultation. The economic analysis finds that none of the seven outcomes relative to significant adverse effect thresholds set forth by the Office of Management and Budget are relevant to this analysis. Thus, based on information in the economic analysis, energy-related impacts associated with *Chromolaena frustrata* conservation activities within critical habitat are not expected. As such, the designation of critical habitat is not expected to significantly affect energy supplies, distribution, or use. Therefore, this action is not a significant energy action, and no Statement of Energy Effects is required.

Unfunded Mandates Reform Act (2 U.S.C. 1501 et seq.)

In accordance with the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*), we make the following findings:

(1) This rule will not produce a Federal mandate. In general, a Federal mandate is a provision in legislation, statute, or regulation that would impose an enforceable duty upon State, local, or tribal governments, or the private sector, and includes both ''Federal intergovernmental mandates'' and ''Federal private sector mandates.'' These terms are defined in 2 U.S.C. 658(5)–(7). ''Federal intergovernmental mandate'' includes a regulation that ''would impose an enforceable duty upon State, local, or tribal governments'' with two exceptions. It excludes ''a condition of Federal assistance.'' It also excludes ''a duty arising from participation in a voluntary Federal program,'' unless the regulation ''relates to a then-existing Federal program under which $500,000,000 or more is provided annually to State, local, and tribal governments under entitlement authority,'' if the provision would ''increase the stringency of conditions of assistance'' or ''place caps upon, or otherwise decrease, the Federal Government's responsibility to provide funding,'' and the State, local, or tribal governments ''lack authority'' to adjust accordingly. At the time of enactment, these entitlement programs were: Medicaid; Aid to Families with Dependent Children work programs; Child Nutrition; Food Stamps; Social Services Block Grants; Vocational Rehabilitation State Grants; Foster Care, Adoption Assistance, and Independent Living; Family Support Welfare Services; and Child Support Enforcement. ''Federal private sector

mandate'' includes a regulation that ''would impose an enforceable duty upon the private sector, except (i) a condition of Federal assistance or (ii) a duty arising from participation in a voluntary Federal program.''

The designation of critical habitat does not impose a legally binding duty on non-Federal Government entities or private parties. Under the Act, the only regulatory effect is that Federal agencies must ensure that their actions do not destroy or adversely modify critical habitat under section 7. While non-Federal entities that receive Federal funding, assistance, or permits, or that otherwise 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. Furthermore, to the extent that non-Federal entities are indirectly impacted because they receive Federal assistance or participate in a voluntary Federal aid program, the Unfunded Mandates Reform Act would not apply, nor would critical habitat shift the costs of the large entitlement programs listed above onto State governments.

(2) We do not believe that this rule will significantly or uniquely affect small governments because it will not produce a Federal mandate of $100 million or greater in any year, that is, it is not a ''significant regulatory action'' under the Unfunded Mandates Reform Act. Small governments will be affected only to the extent that any programs having Federal funds, permits, or other authorized activities must ensure that their actions will not adversely affect the critical habitat. The final economic analysis concludes incremental impacts may occur due to administrative costs of section 7 consultations for activities related to commercial, residential, and recreational development and associated actions; however, these are not expected to significantly affect small government entities. Consequently, a Small Government Agency Plan is not required.

Takings—Executive Order 12630

In accordance with Executive Order 12630 (Government Actions and Interference with Constitutionally Protected Private Property Rights), we have analyzed the potential takings implications of designating critical habitat for *Chromolaena frustrata* in a takings implications assessment. As discussed above, the designation of critical habitat affects only Federal actions. Although private parties that receive Federal funding or assistance, or that 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 takings implications assessment concludes that this designation of critical habitat for *Chromolaena frustrata* does not pose significant takings implications for lands within or affected by the designation.

Federalism—Executive Order 13132

In accordance with Executive Order 13132 (Federalism), this rule does not have significant Federalism effects. A federalism summary impact statement is not required. In keeping with Department of the Interior and Department of Commerce policy, we request information from, and coordinated development of, this critical habitat designation with appropriate State resource agencies in Florida. From a federalism perspective, the designation of critical habitat directly affects only the responsibilities of Federal agencies. The Act imposes no other duties with respect to critical habitat, either for States and local governments, or for anyone else. As a result, the rule does not have substantial direct effects either on the States, or on the relationship between the national government and the States, or on the distribution of powers and responsibilities among the various levels of government. The designation may have some benefit to these governments in that the areas that contain the physical or biological features essential to the conservation of the species are more clearly defined, and the elements of the physical and biological features of the habitat necessary to the conservation of the species are specifically identified. This information does not alter where and what federally sponsored activities may occur. However, it may assist local governments in long-range planning (rather than having them wait for case-by-case section 7 consultations to occur).

Where State and local governments require approval or authorization from a Federal agency for actions that may affect critical habitat, consultation under section 7(a)(2) would be required. While non-Federal entities that receive Federal funding, assistance, or permits, or that otherwise 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.

Civil Justice Reform—Executive Order 12988

In accordance with Executive Order 12988 (Civil Justice Reform), the Office of the Solicitor has determined that the rule does not unduly burden the judicial system and that it meets the applicable standards set forth in sections 3(a) and 3(b)(2) of the Order. We are designating critical habitat in accordance with the provisions of the Act. To assist the public in understanding the habitat needs of the species, the rule identifies the elements of physical or biological features essential to the conservation of *Chromolaena frustrata.* The designated areas of critical habitat are presented on maps, and the rule provides several options for the interested public to obtain more detailed location information, if desired.

Paperwork Reduction Act of 1995 (44 U.S.C. 3501 et seq.)

This rule does not contain any new collections of information that require approval by OMB under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). This rule will not impose recordkeeping or reporting requirements on State or local governments, individuals, businesses, or organizations. 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.

National Environmental Policy Act (42 U.S.C. 4321 et seq.)

It is our position that, outside the jurisdiction of the U.S. Court of Appeals for the Tenth Circuit, we do not need to prepare environmental analyses pursuant to the National Environmental Policy Act in connection with designating critical habitat under the Act. We published a notice outlining our reasons for this determination in the **Federal Register** on October 25, 1983 (48 FR 49244). This position was upheld by the U.S. Court of Appeals for the Ninth Circuit (*Douglas County* v. *Babbitt,* 48 F.3d 1495 (9th Cir. 1995), cert. denied 516 U.S. 1042 (1996)).

Government-to-Government Relationship With Tribes

In accordance with the President's memorandum of April 29, 1994 (Government-to-Government Relations with Native American Tribal Governments; 59 FR 22951), Executive Order 13175 (Consultation and

Coordination With Indian Tribal Governments), and the Department of the Interior's manual at 512 DM 2, we readily acknowledge our responsibility to communicate meaningfully with recognized Federal Tribes on a government-to-government basis. In accordance with Secretarial Order 3206 of June 5, 1997 (American Indian Tribal Rights, Federal-Tribal Trust Responsibilities, and the Endangered Species Act), we readily acknowledge our responsibilities to work directly with tribes in developing programs for healthy ecosystems, to acknowledge that tribal lands are not subject to the same controls as Federal public lands, to remain sensitive to Indian culture, and to make information available to tribes.

We determined that there are no tribal lands occupied by *Chromolaena frustrata* at the time of listing that contain the features essential to conservation of the species, and no tribal lands unoccupied by *C. frustrata* that are essential for the conservation of the species. Therefore, we are not designating critical habitat for *C. frustrata* on tribal lands.

References Cited

A complete list of all references cited is available on the Internet at *http://www.regulations.gov* and upon request from the, U.S. Fish and Wildlife Service, South Florida Ecological Services Office (see **FOR FURTHER INFORMATION CONTACT**).

Authors

The primary authors of this rulemaking are the staff members of the U.S. Fish and Wildlife Service, South Florida Ecological Services Office.

List of Subjects in 50 CFR Part 17

Endangered and threatened species, Exports, Imports, Reporting and recordkeeping requirements, Transportation.

Regulation Promulgation

Accordingly, we amend part 17, subchapter B of chapter I, title 50 of the Code of Federal Regulations, 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 § 17.12(h) by revising the entry for *Chromolaena frustrata* under Flowering Plants in the List of Endangered and Threatened Plants to read as follows:

§ 17.12 Endangered and threatened plants.

* * * * *

(h) * * *

Species		Historic range	Family	Status	When listed	Critical habitat	Special rules
Scientific name	Common name						
FLOWERING PLANTS							
*	*	*	*	*	*		*
Chromolaena frustrata.	Cape Sable thoroughwort.	U.S.A. (FL)	Asteraceae	E	826	17.96(a)	NA
	U.S.A. (FL)	NA		E		17.96(h)	NA
*	*	*	*	*	*		*

■ 3. Amend § 17.96(a) by adding an entry for ''*Chromolaena frustrata* (Cape Sable thoroughwort)'' in alphabetical order under the family Asteraceae, to read as follows:

§ 17.96 Critical habitat—plants.

(a) *Flowering plants.*

* * * * *

Family Asteraceae: *Chromolaena frustrata* (Cape Sable thoroughwort)

(1) Critical habitat units for *Chromolaena frustrata* are depicted for Miami-Dade and Monroe Counties, Florida, on the maps below.

(2) Within these areas, the primary constituent elements of the physical or biological features essential to the conservation of *Chromolaena frustrata* consist of four components:

(i) Areas of upland habitats consisting of coastal berm, coastal rock barren, coastal hardwood hammock, rockland hammocks, and buttonwood forest.

(A) Coastal berm habitat that contains:

(*1*) Open to semi-open canopy, subcanopy, and understory; and

(*2*) Substrate of coarse, calcareous, storm-deposited sediment.

(B) Coastal rock barren (Keys cactus barren, Keys tidal rock barren) habitat that contains:

(*1*) Open to semi-open canopy and understory; and

(*2*) Limestone rock substrate.

(C) Coastal hardwood hammock habitat occurring in Everglades National Park that contains:

(*1*) Canopy gaps and edges with an open to semi-open canopy, subcanopy, and understory; and

(*2*) Substrate of marl covered with a thin layer of highly organic soil.

(D) Rockland hammock habitat that contains:

(*1*) Canopy gaps and edges with an open to semi-open canopy, subcanopy, and understory; and

(*2*) Substrate with a thin layer of highly organic soil, marl, humus, or leaf litter on top of the underlying limestone.

(E) Buttonwood forest habitat that contains:

(*1*) Open to semi-open canopy and understory; and

(*2*) Substrate with calcareous marl muds, calcareous sands, or limestone rock.

(ii) Plant communities of predominately native vegetation with either no invasive, nonnative species or with low enough quantities of nonnative, invasive plant species to have minimal effect on the survival of *Chromolaena frustrata.*

(iii) A disturbance regime, due to the effects of strong winds or saltwater inundation from storm surge or infrequent tidal inundation, that creates canopy openings in coastal berm, coastal rock barren, coastal hardwood hammock, rockland hammocks, and buttonwood forest.

(iv) Habitats that are connected and of sufficient area to sustain viable populations in coastal berm, coastal rock barren, coastal hardwood hammock, rockland hammocks, and buttonwood forest.

(3) Critical habitat does not include manmade structures (such as buildings, aqueducts, runways, roads, and other paved areas) and the land on which they are located exists within the legal boundaries on February 7, 2014.

(4) *Critical habitat map units.* Unit maps were developed using ESRI

ArcGIS mapping software along with various spatial data layers. ArcGIS was also used to calculate the size of habitat areas. The projection used in mapping and calculating distances and locations within the units was North American Albers Equal Area Conic, NAD 83. The maps in this entry, as modified by any accompanying regulatory text, establish the boundaries of the critical habitat designation. The coordinates or plot points or both on which each map is based are available to the public at the Service's Internet site at *http://www.fws.gov/verobeach/,* on the Federal eRulemaking Portal at *http://www.regulations.gov* at Docket No. FWS–R4–ES–2013–0029, and at the field office responsible for this designation. You may obtain field office location information by contacting one of the Service regional offices, the addresses of which are listed at 50 CFR 2.2.

(5) Index map of all critical habitat units for *Chromolaena frustrata* follows:

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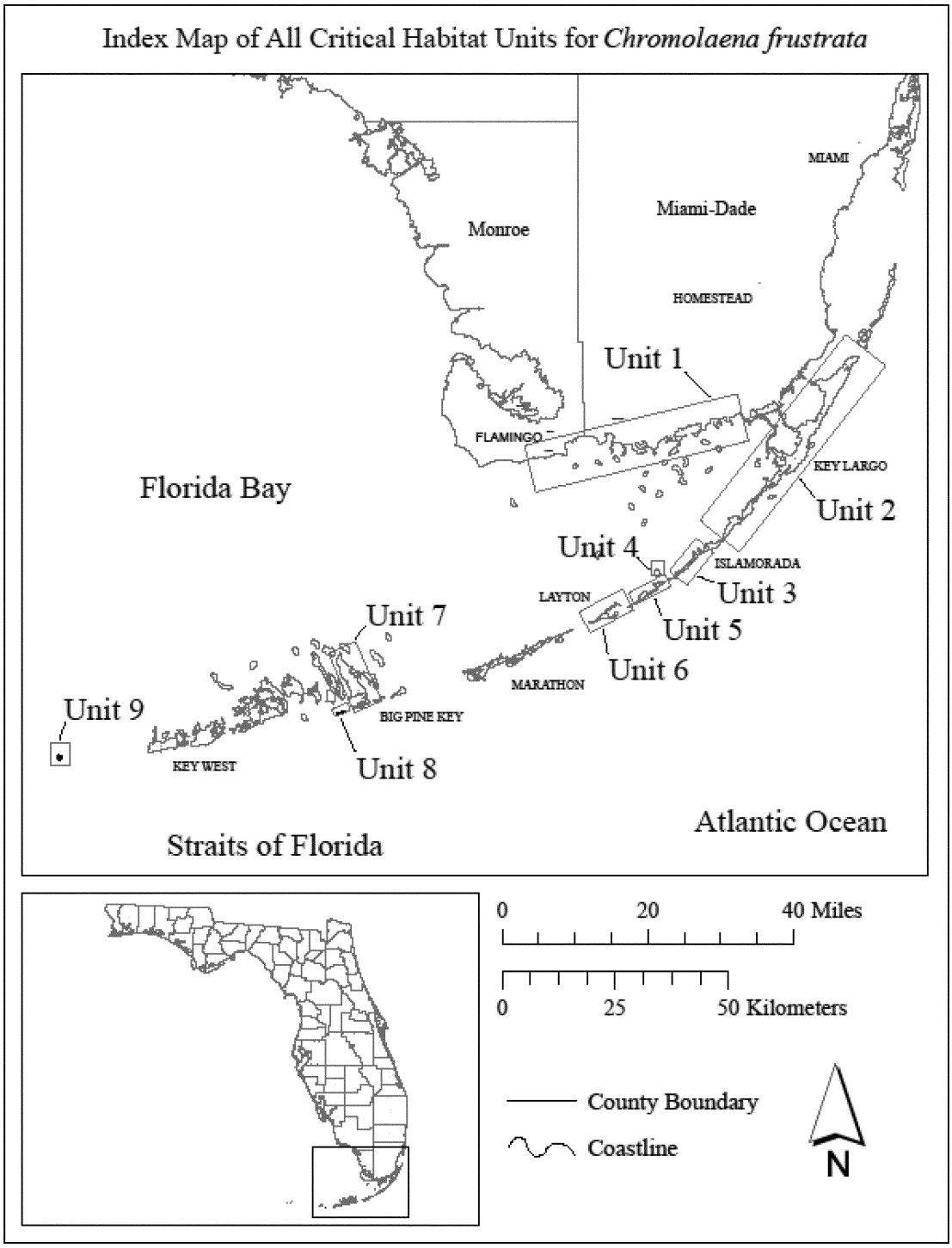
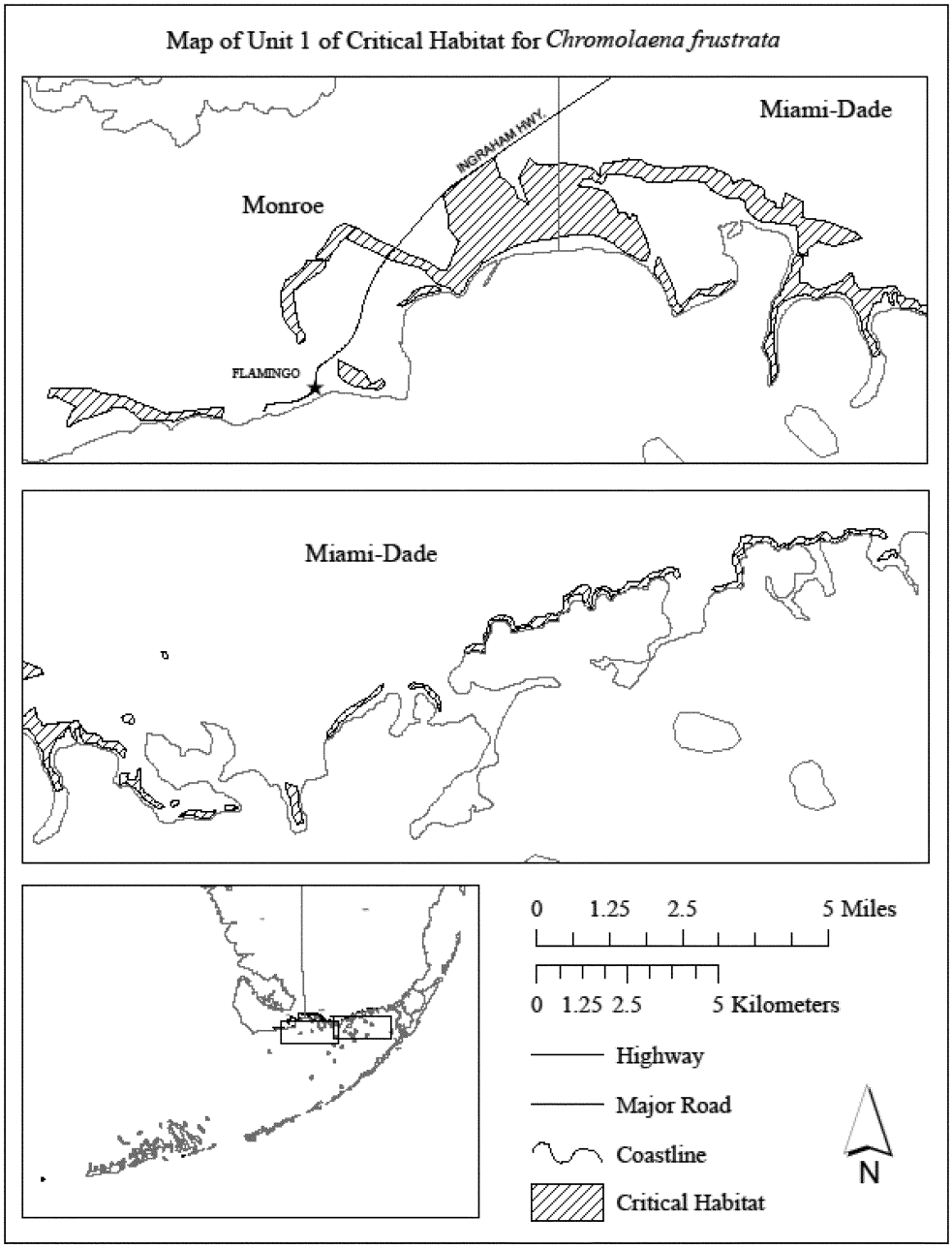


(6) Unit 1: Everglades National Park, Monroe and Miami-Dade Counties, Florida.

(i) *General Description:* Unit 1 consists of a total of 6,166 acres (2,495 hectares) in Monroe and Miami-Dade Counties. This unit is composed entirely of lands in Federal ownership, 100 percent of which are located within the Everglades National Park.

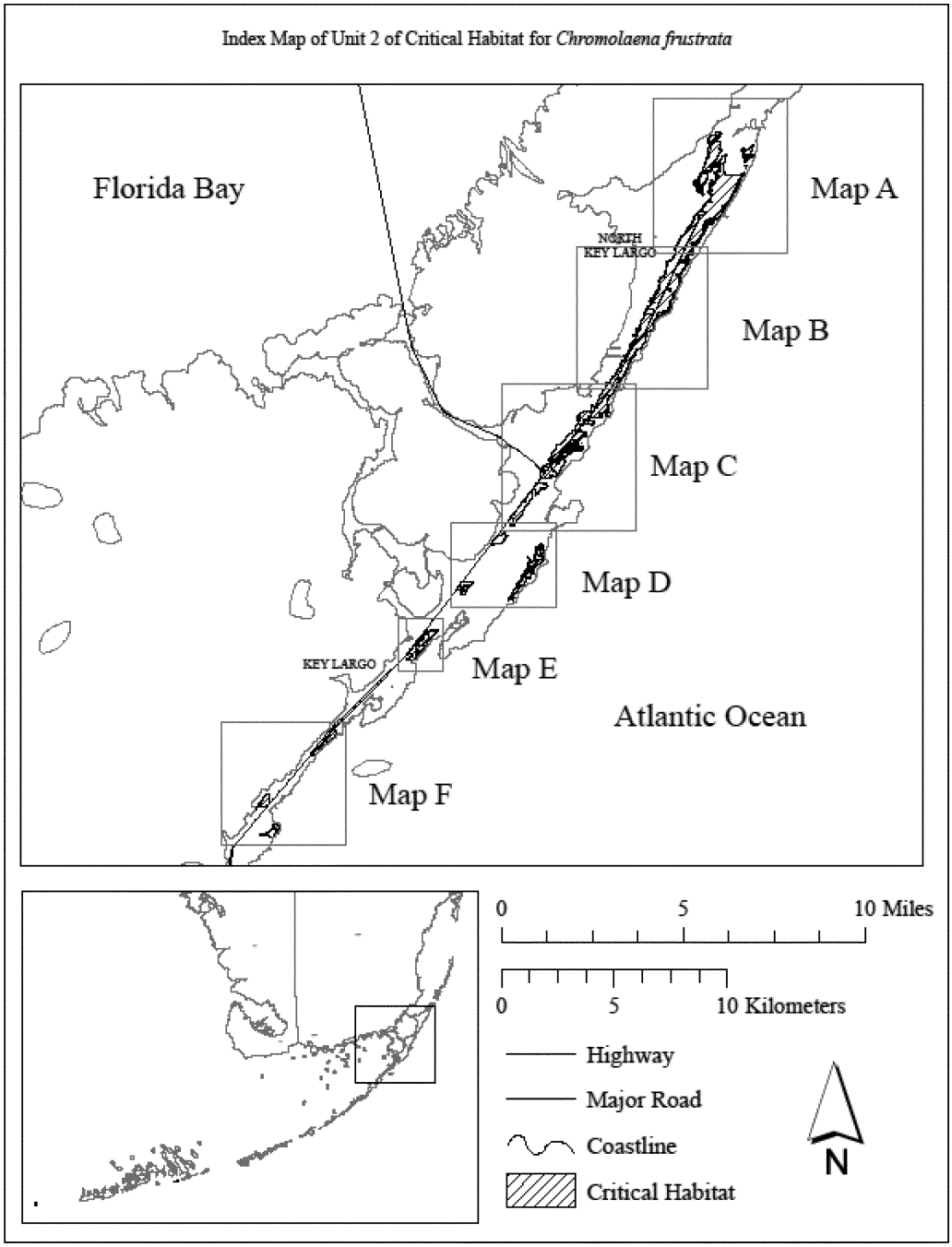
(ii) Map of Unit 1 follows:



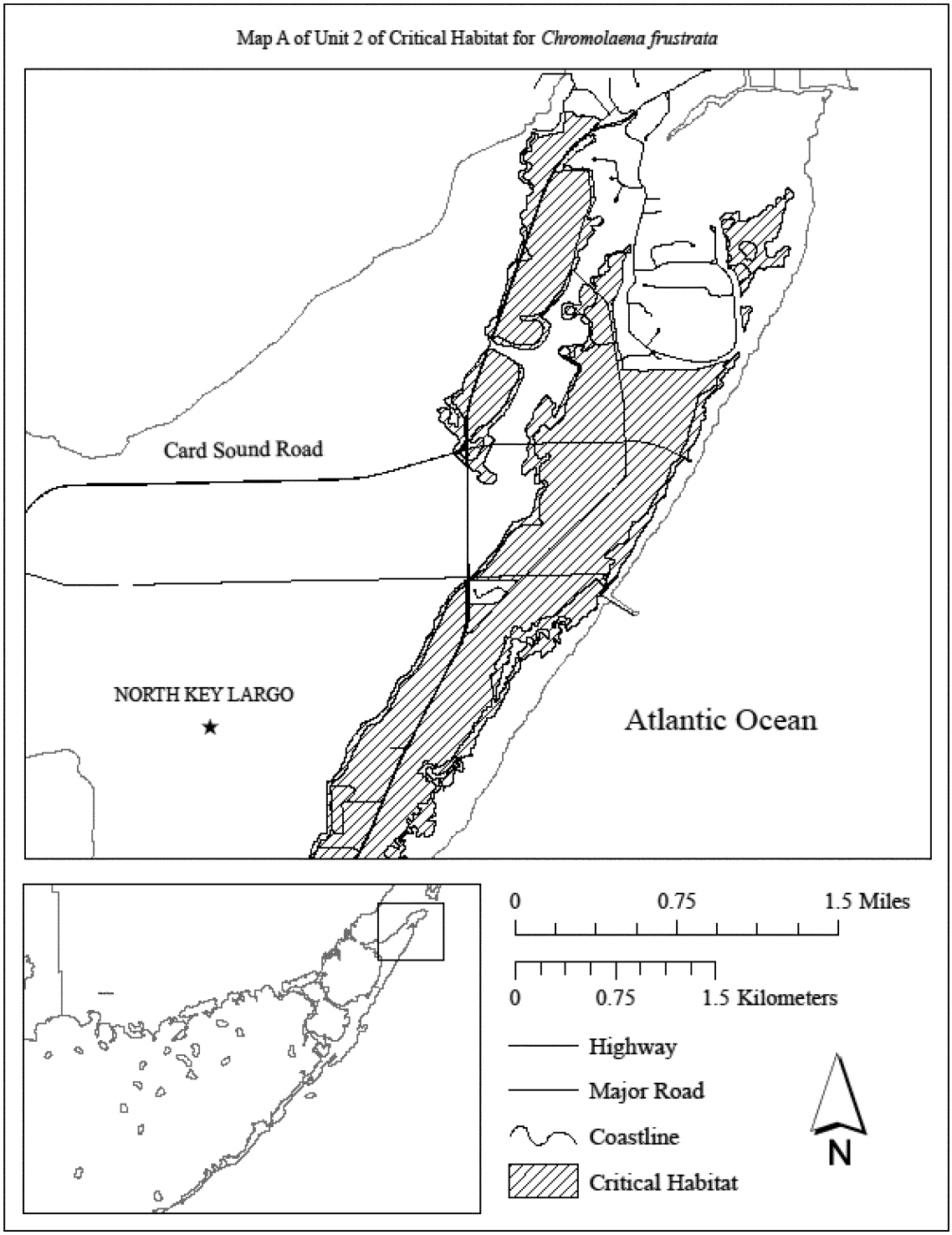
(7) Unit 2: Key Largo, Monroe County, Florida.

(i) *General Description:* Unit 2 consists of a total of 3,431 acres (1,388 hectares) in Monroe County. This unit is composed of Federal lands within Crocodile Lake National Wildlife Refuge (NWR) (804 acres (325 hectares)); State lands within Dagny Johnson Botanical State Park, John Pennekamp Coral Reef State Park, and the Florida Keys Wildlife and Environmental Area (2,170 acres (878 hectares)); and parcels in private ownership (457 acres (185 hectares)).

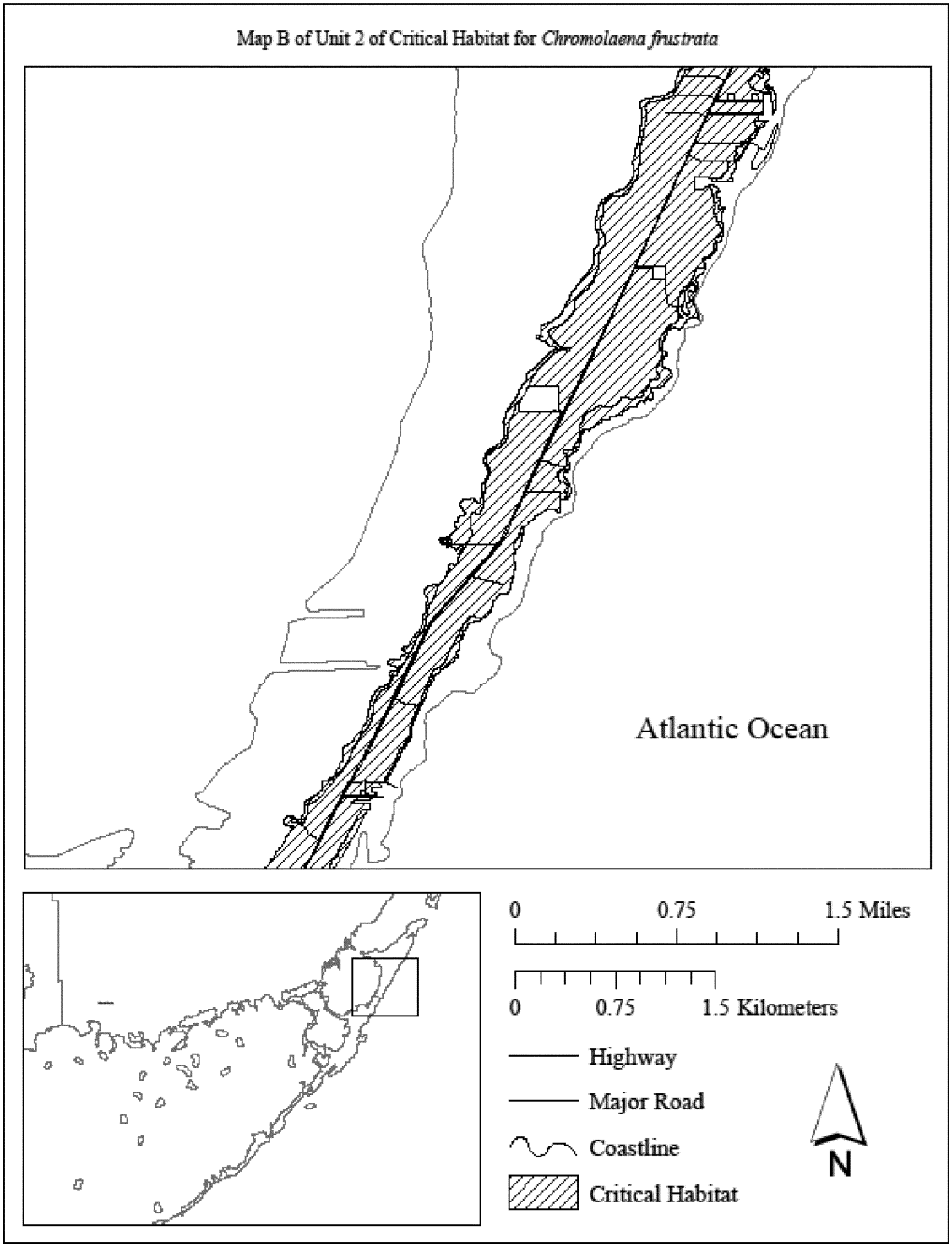
(ii) Index map of Unit 2 follows:



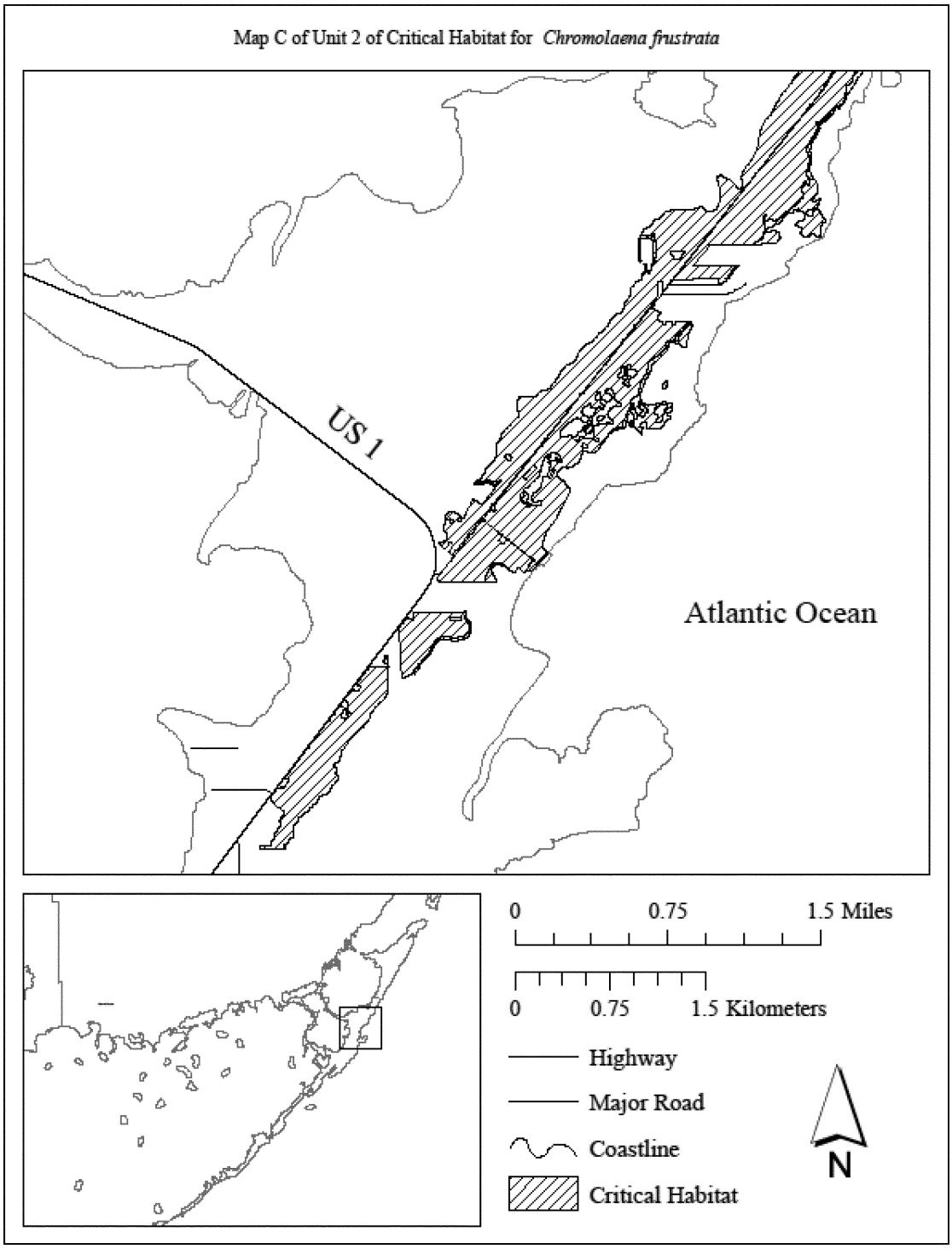
(iii) Map A of Unit 2 follows:



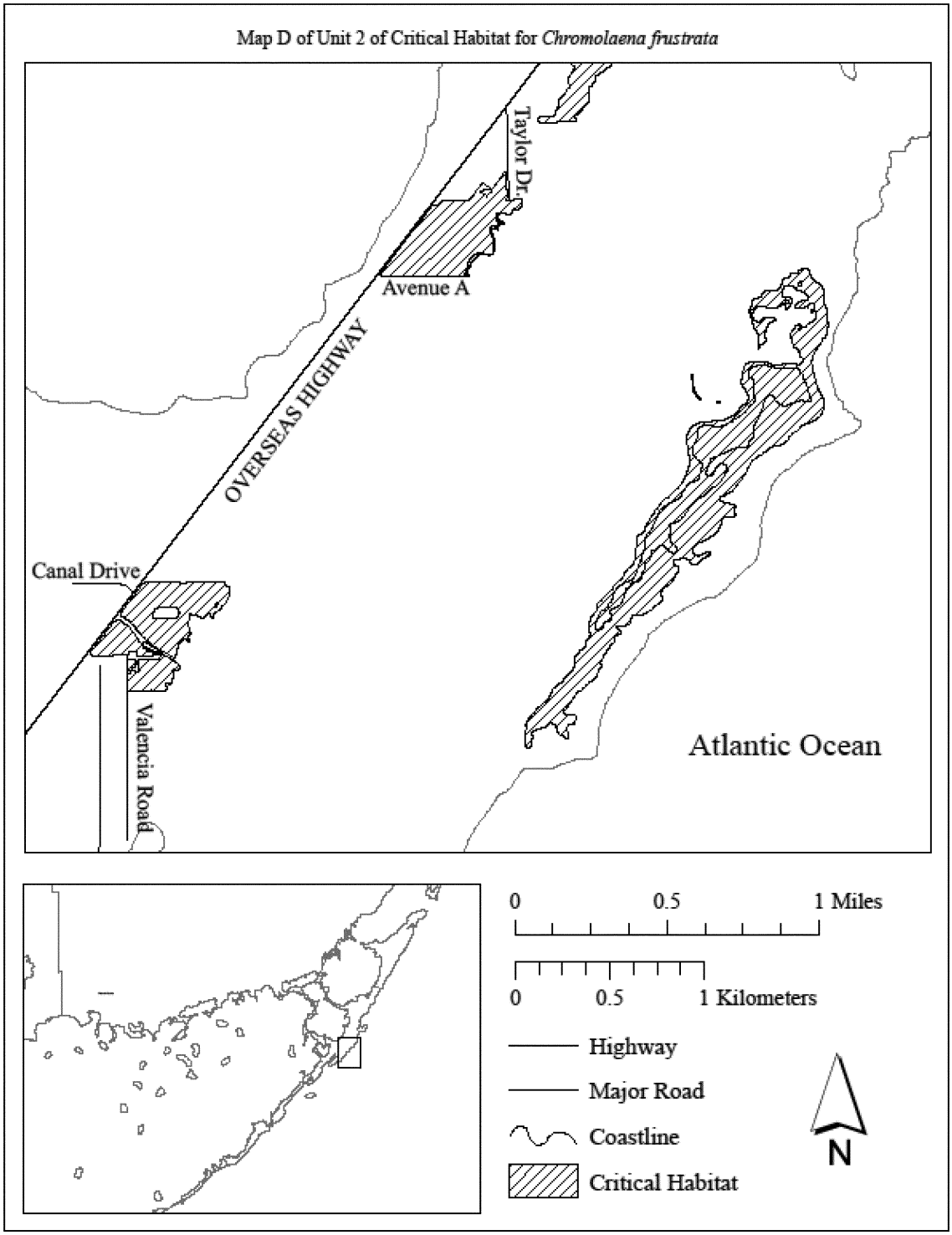
(iv) Map B of Unit 2 follows:



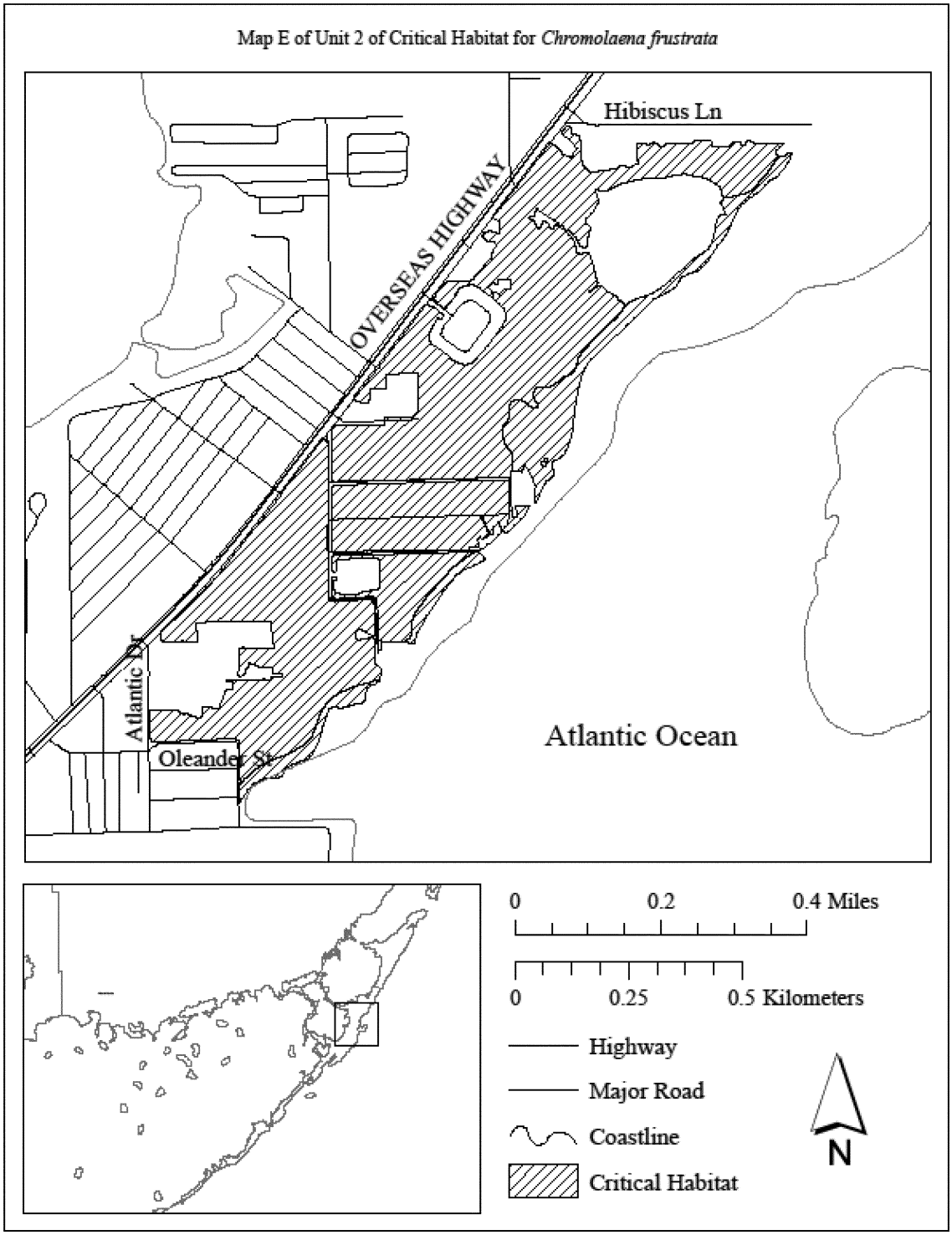
(v) Map C of Unit 2 follows:



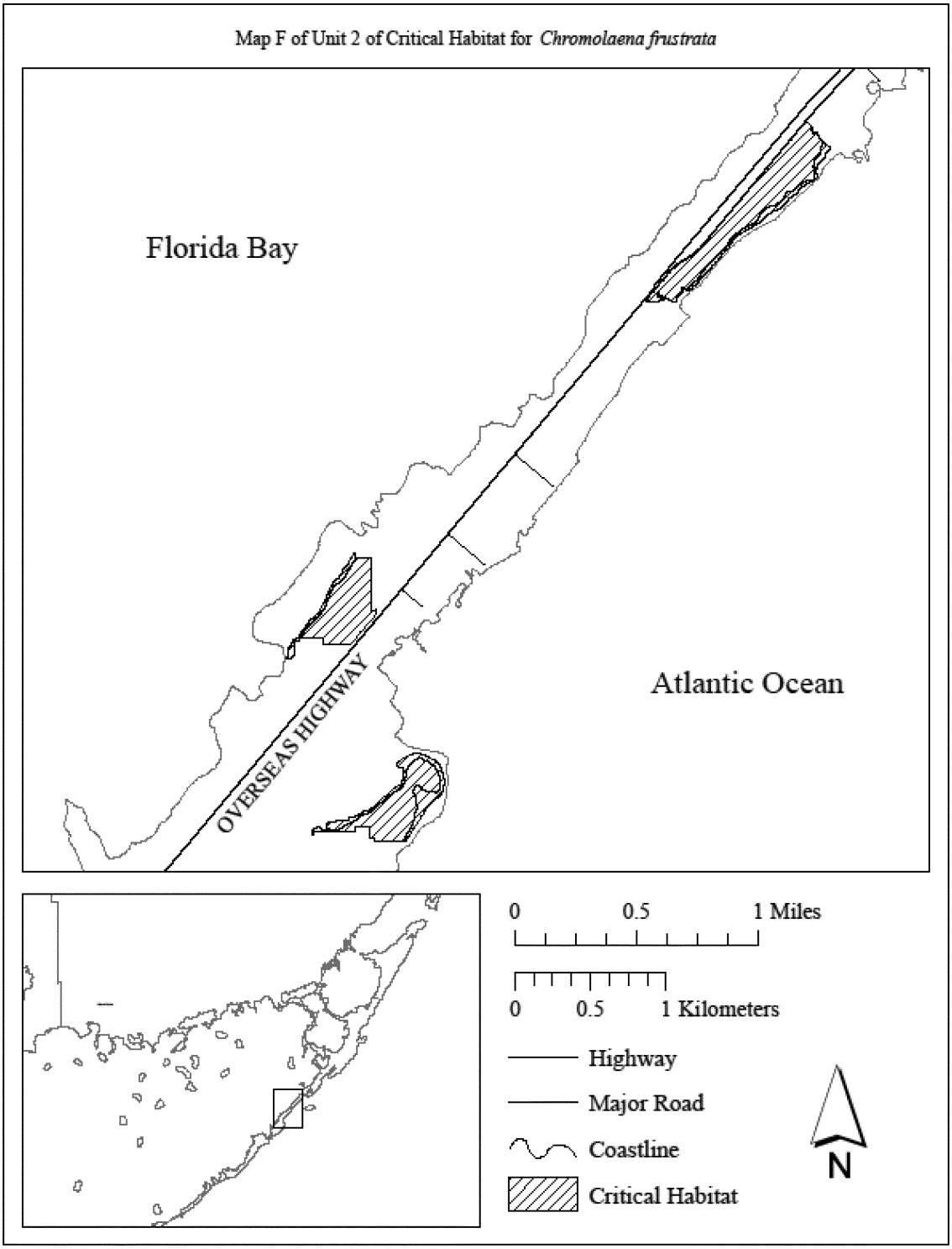
(vi) Map D of Unit 2 follows:



(vii) Map E of Unit 2 follows:



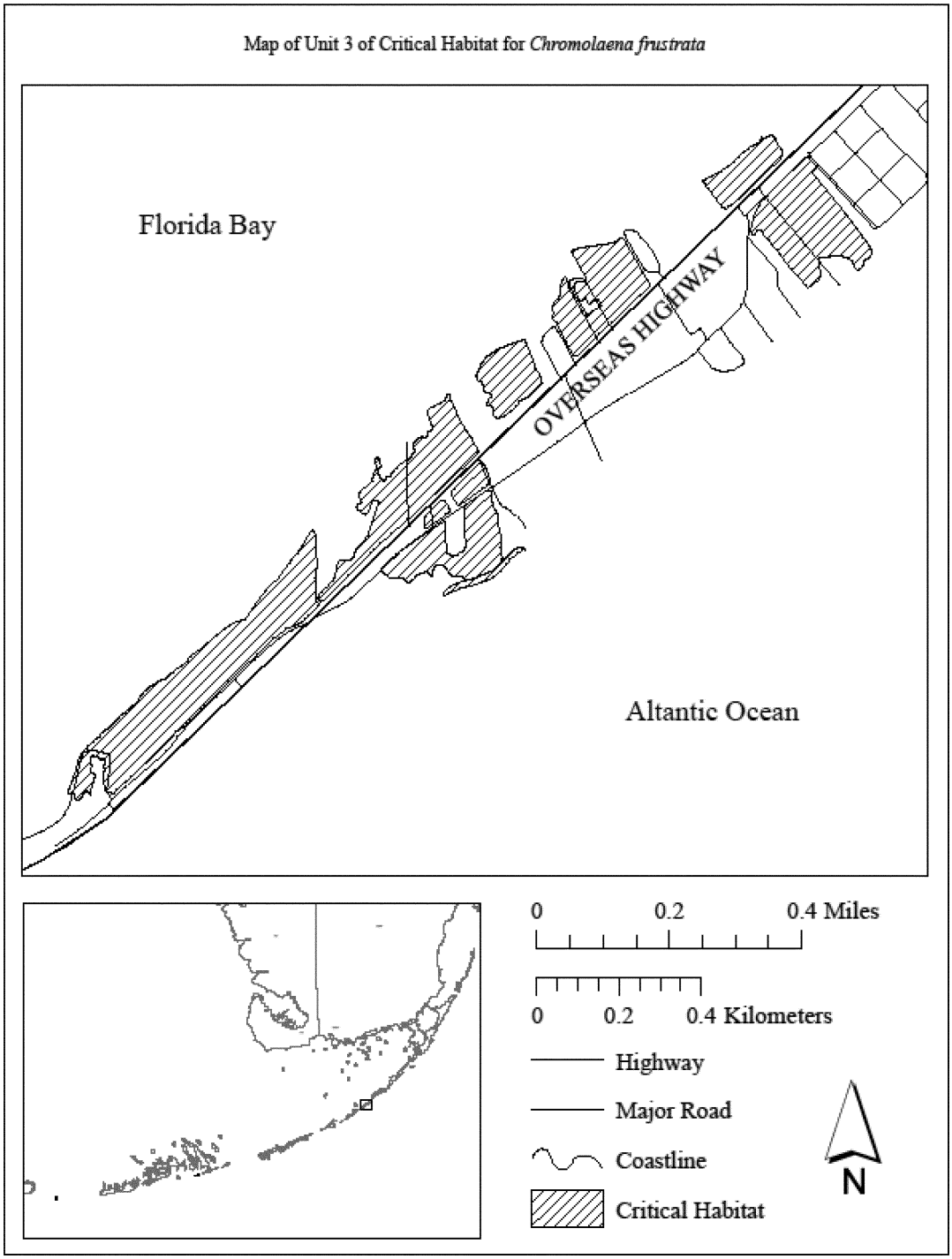
(viii) Map F of Unit 2 follows:



(8) Unit 3: Upper Matecumbe Key, Monroe County, Florida.

(i) *General Description:* Unit 3 consists of 69 acres (28 hectares) in Monroe County. This unit is comprised of State lands within Lignumvitae Key State Botanical Park, Indian Key Historical State Park (24 acres (10 hectares)); City of Islamorada lands within the Key Tree Cactus Preserve and Green Turtle Hammock Park and parcels in private ownership (45 acres (18 hectares)).

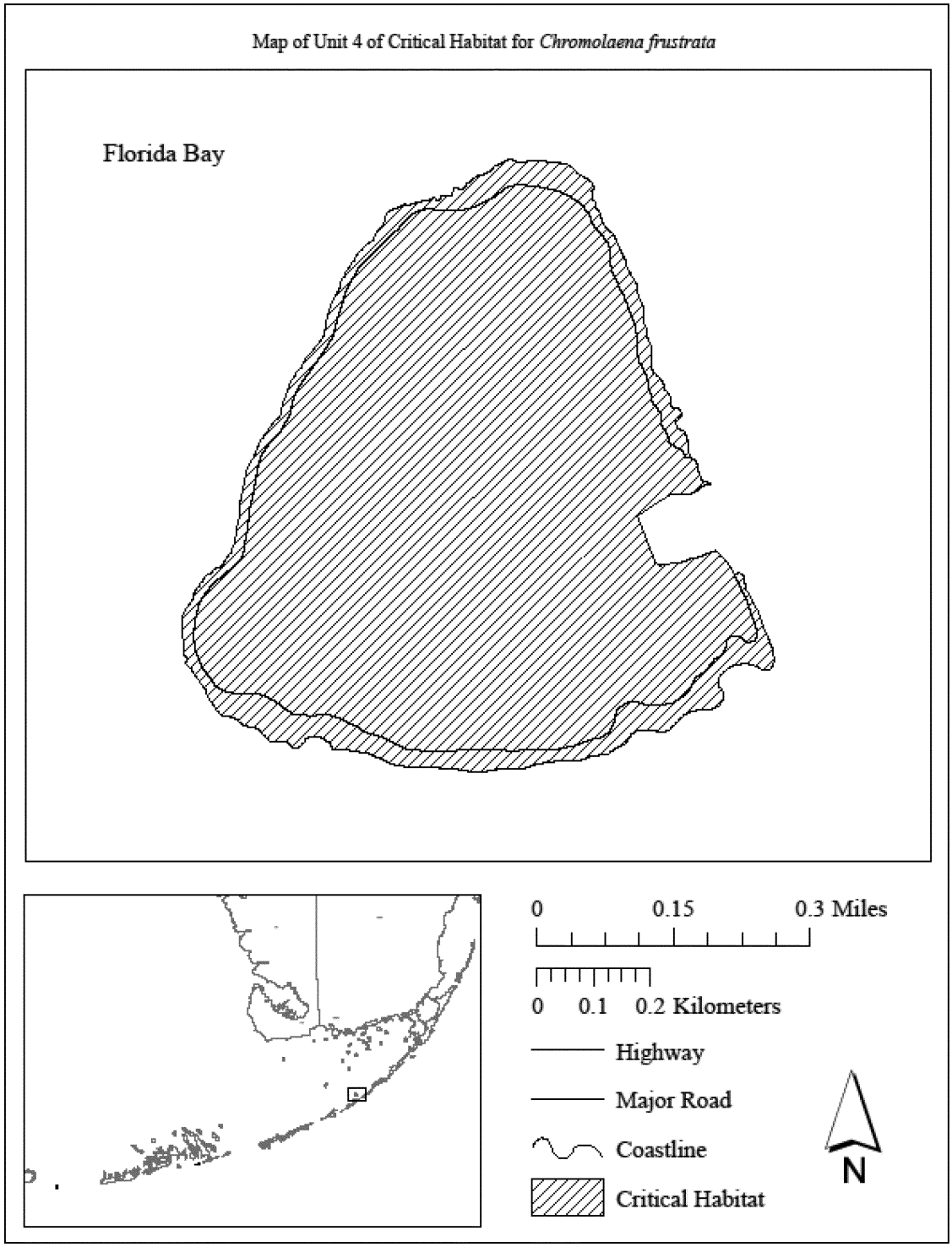
(ii) Map of Unit 3 follows:



(9) Unit 4: Lignumvitae Key, Monroe County, Florida.

(i) *General Description:* Unit 4 consists of a total of 180 acres (73 hectares) in Monroe County. This unit is composed entirely of lands in State ownership, 100 percent of which are located within the Lignumvitae Key Botanical State Park on Lignumvitae Key in the Florida Keys. This unit includes the entire upland area of Lignumvitae Key.

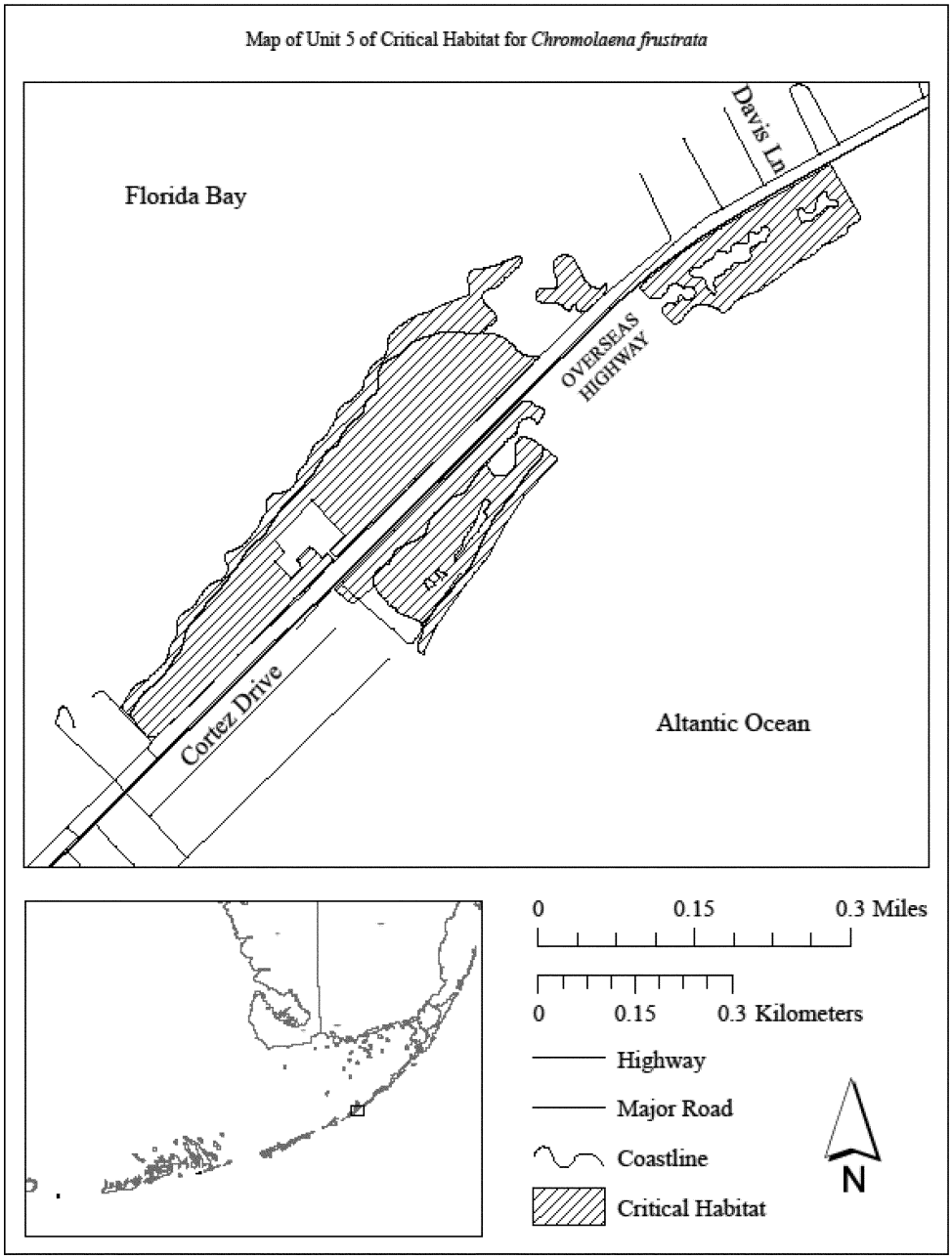
(ii) Map of Unit 4 follows:



(10) Unit 5: Lower Matecumbe Key, Monroe County, Florida.

(i) *General Description:* Unit 5 consists of a total of 44 acres (18 hectares) in Monroe County. The unit is composed of State lands within Lignumvitae Key Botanical State Park and parcels owned by the Florida Department of Transportation (22 acres (9 hectares)), and parcels in private ownership (22 acres (9 hectares)).

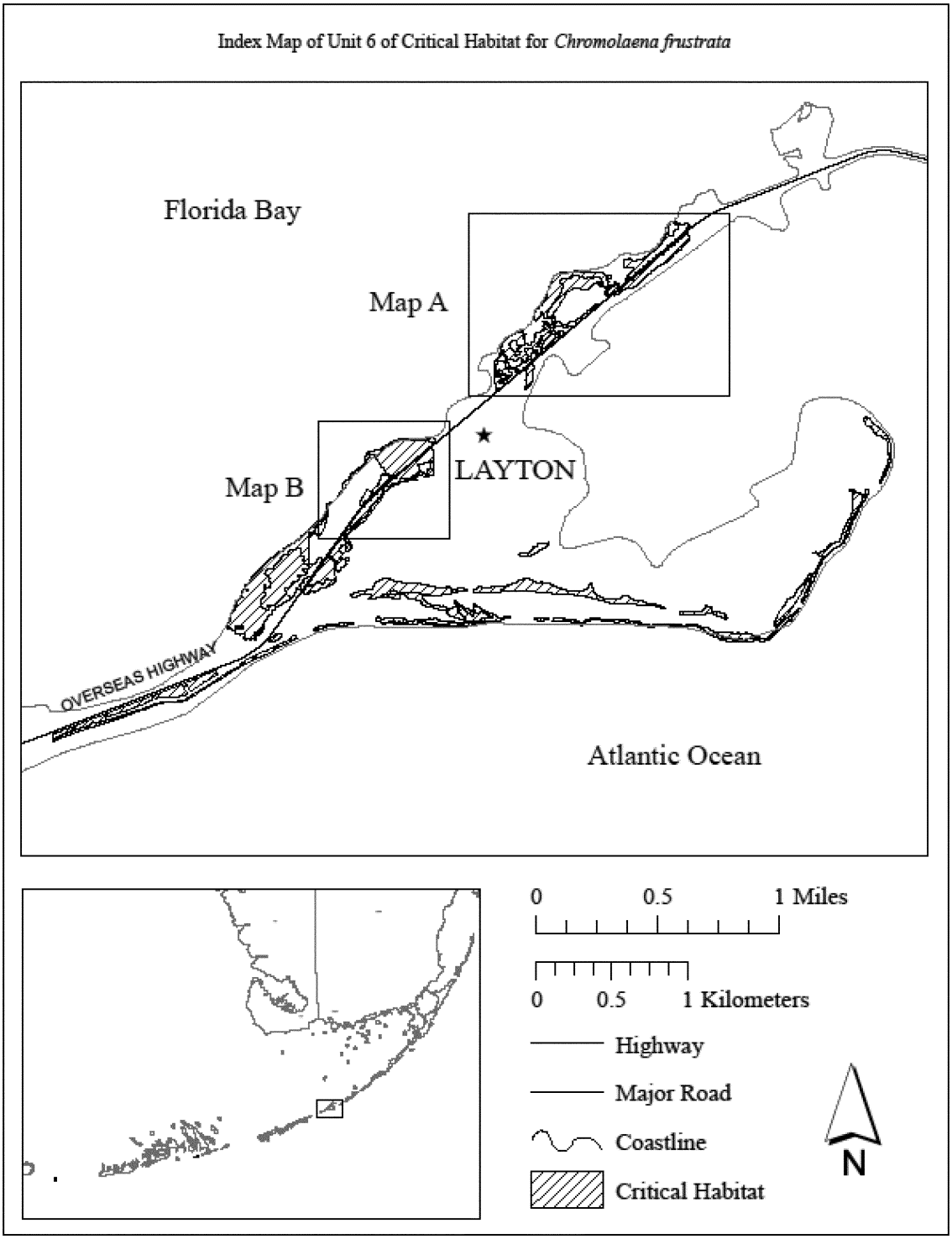
(ii) Map of Unit 5 follows:



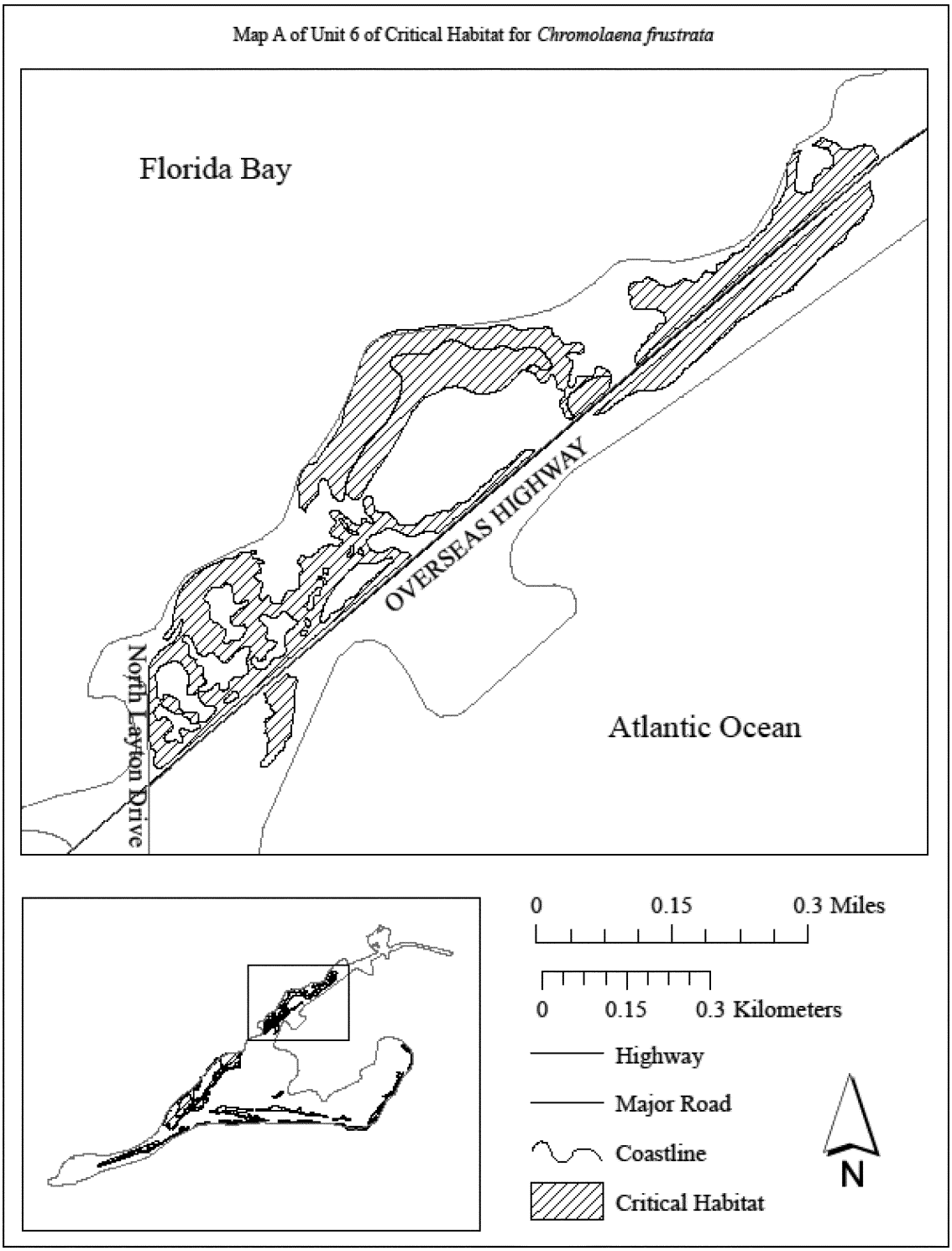
(11) Unit 6: Long Key, Monroe County, Florida.

(i) *General Description:* Unit 6 consists of a total of 208 acres (84 hectares) in Monroe County. This unit is composed of State lands within Long Key State Park (151 acres (61 hectares)) and parcels in private ownership (57 acres (23 hectares)).

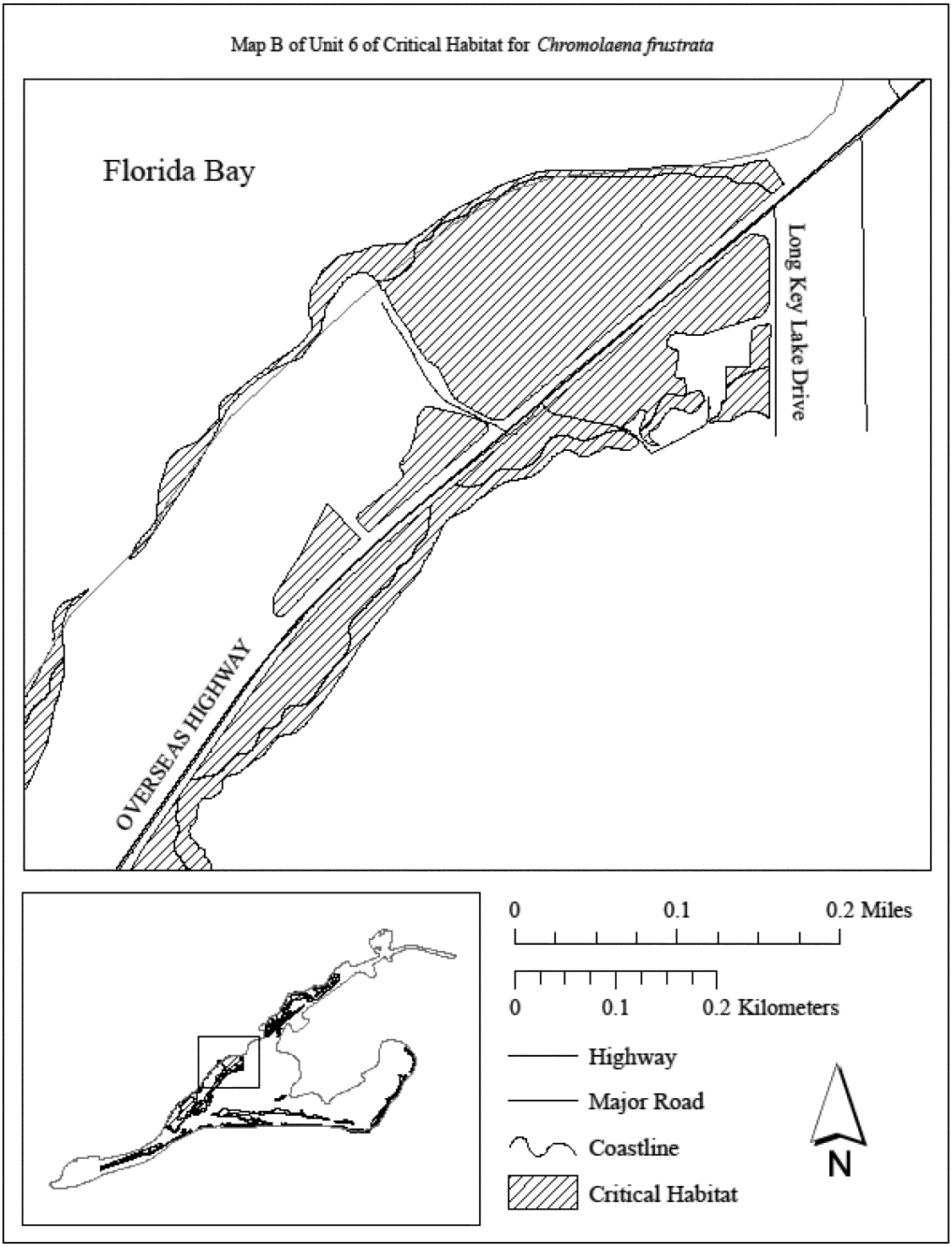
(ii) Index map of Unit 6 follows:



(iii) Map A of Unit 6 follows:



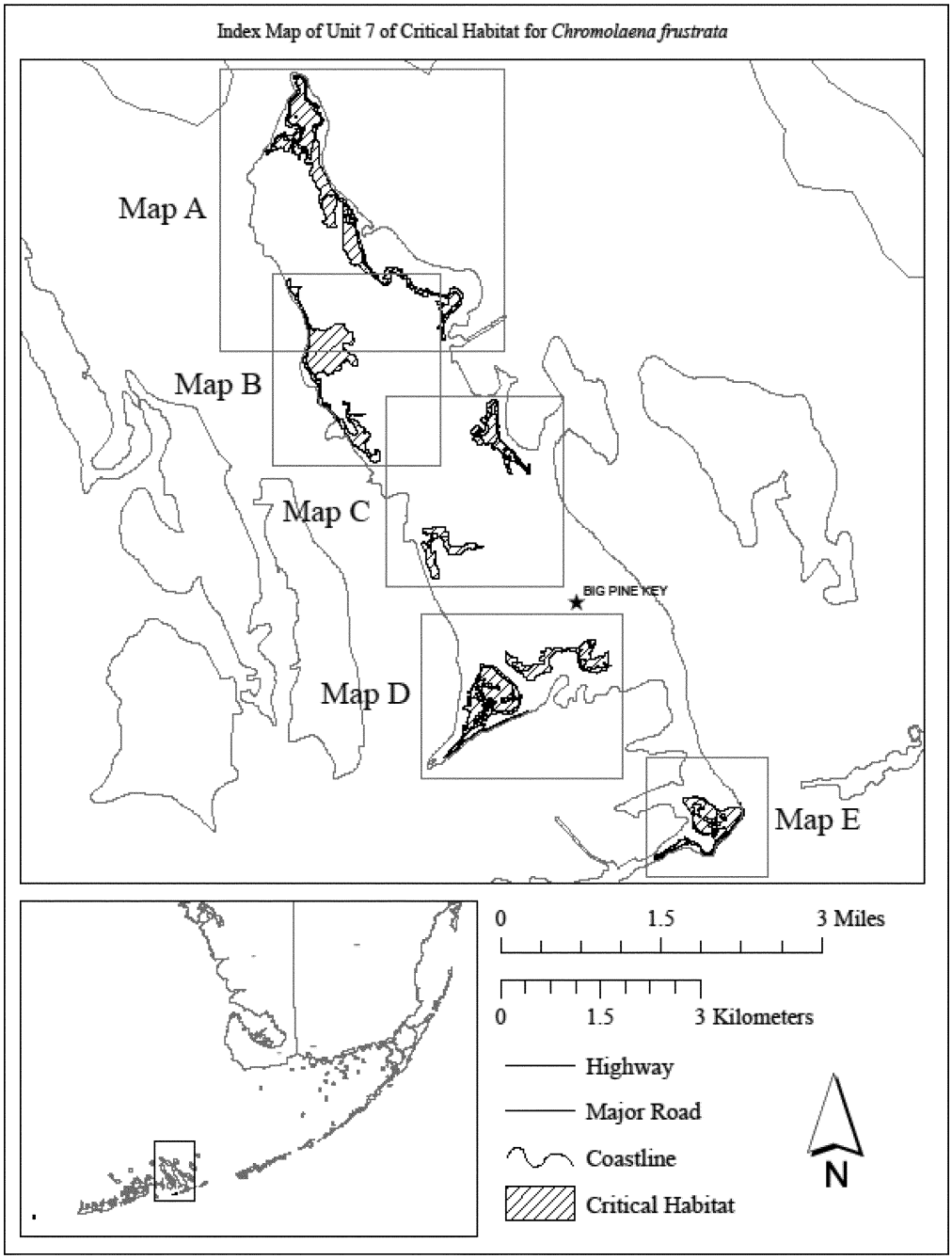
(iv) Map B of Unit 6 follows:



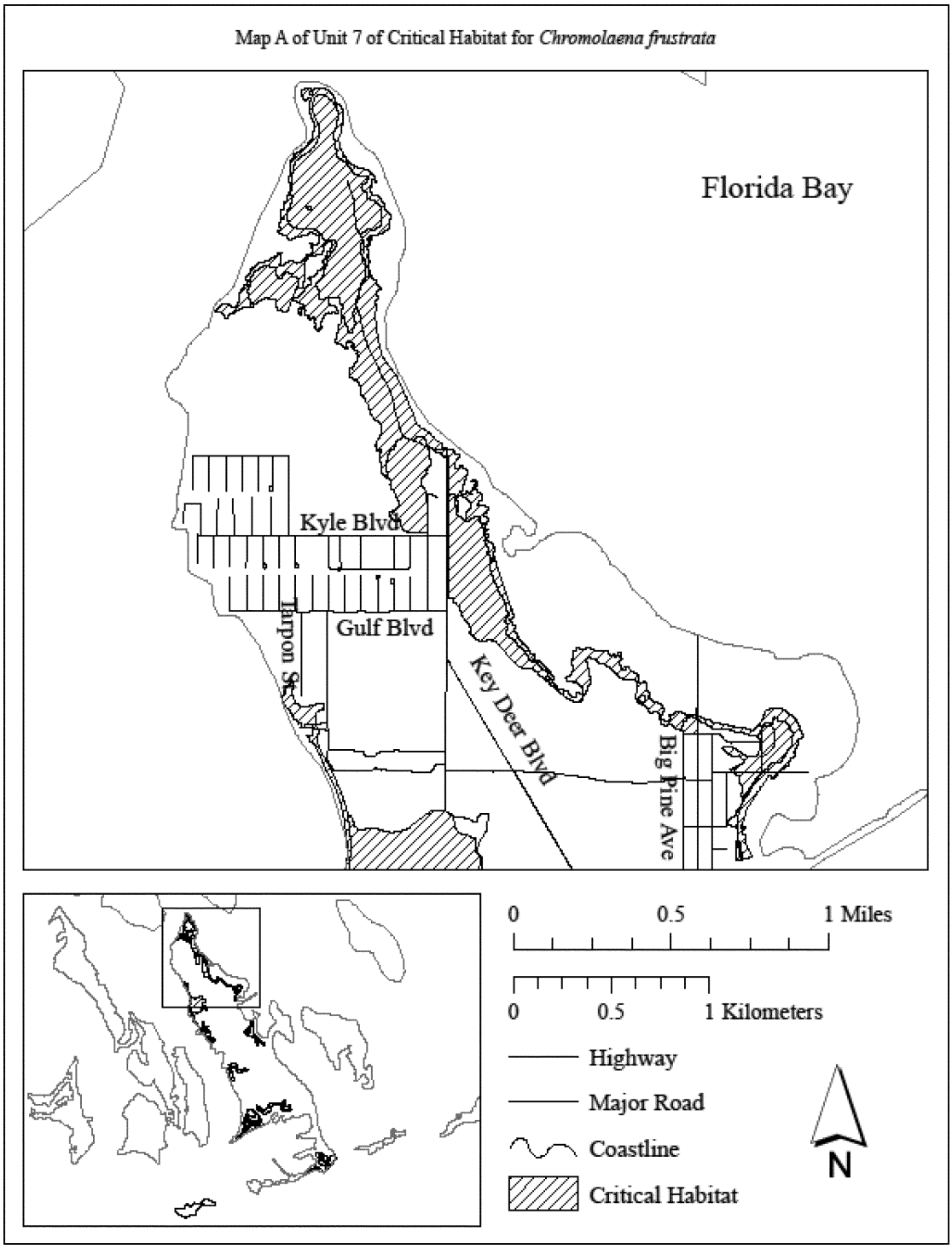
(12) Unit 7: Big Pine Key, Monroe County, Florida.

(i) *General Description:* Unit 7 consists of a total of 780 acres (316 hectares) in Monroe County. This unit is composed of Federal land within the National Key Deer Refuge (686 acres (278 hectares)) and parcels in private ownership (94 acres (38 hectares)).

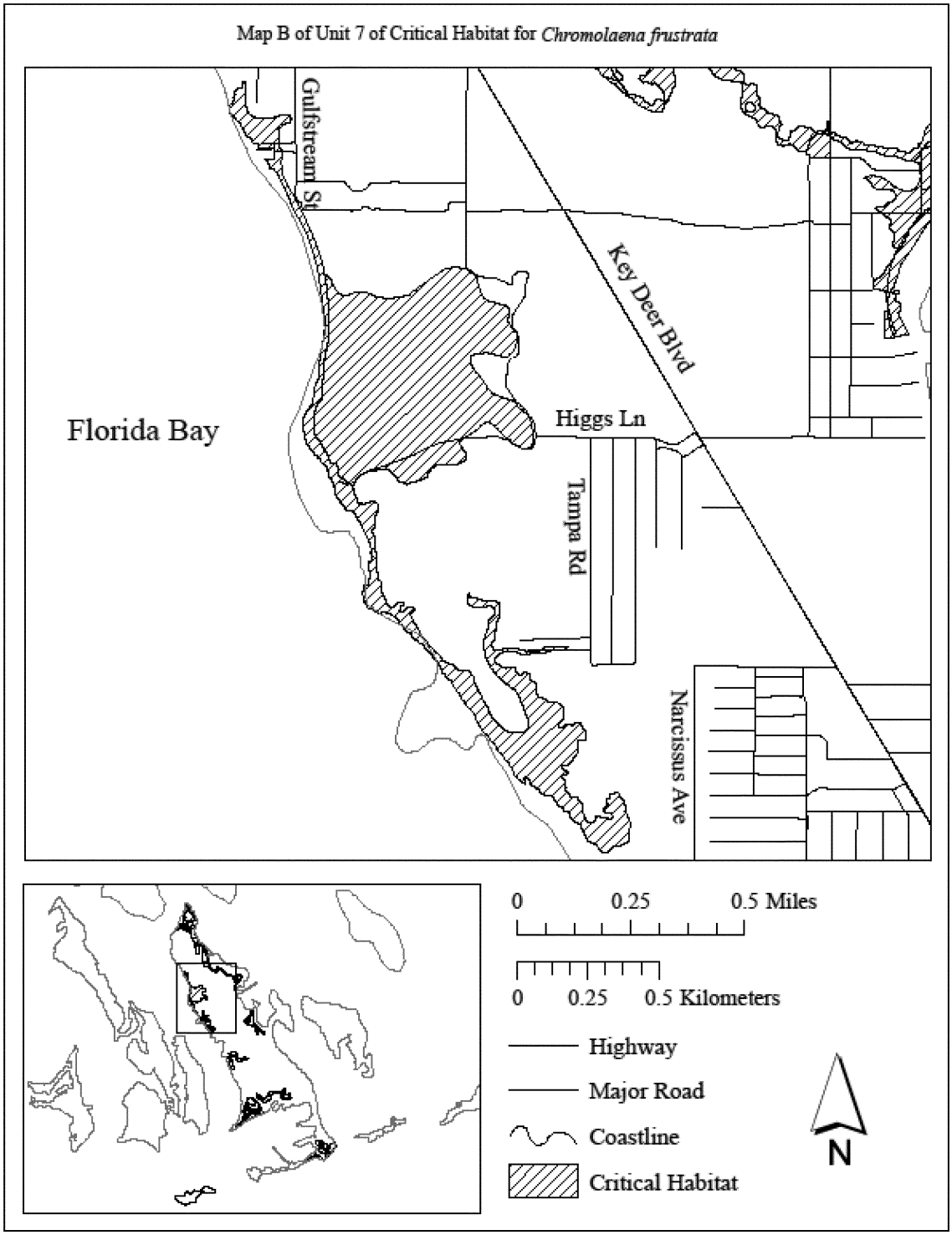
(ii) Index map of Unit 7 follows:



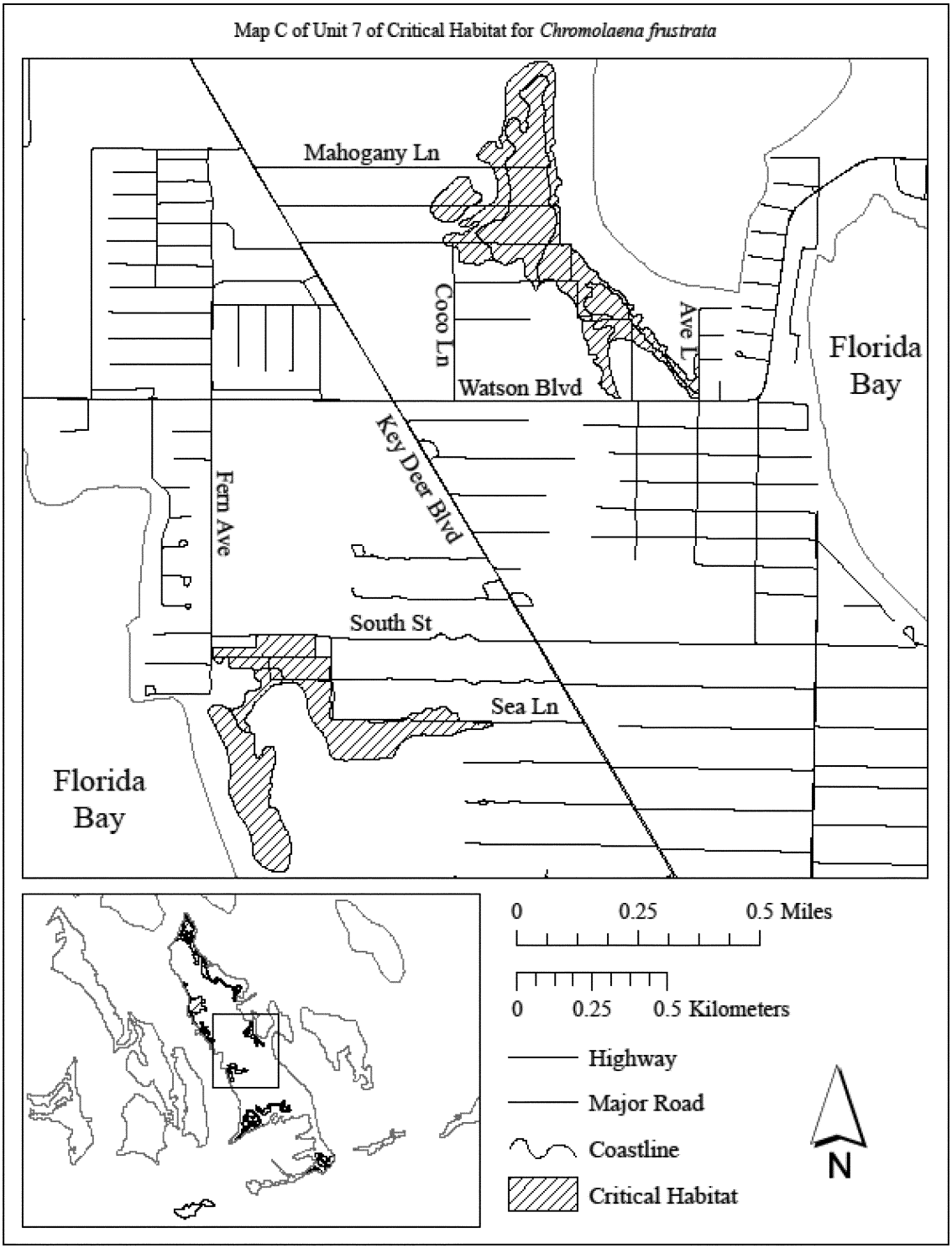
(iii) Map A of Unit 7 follows:



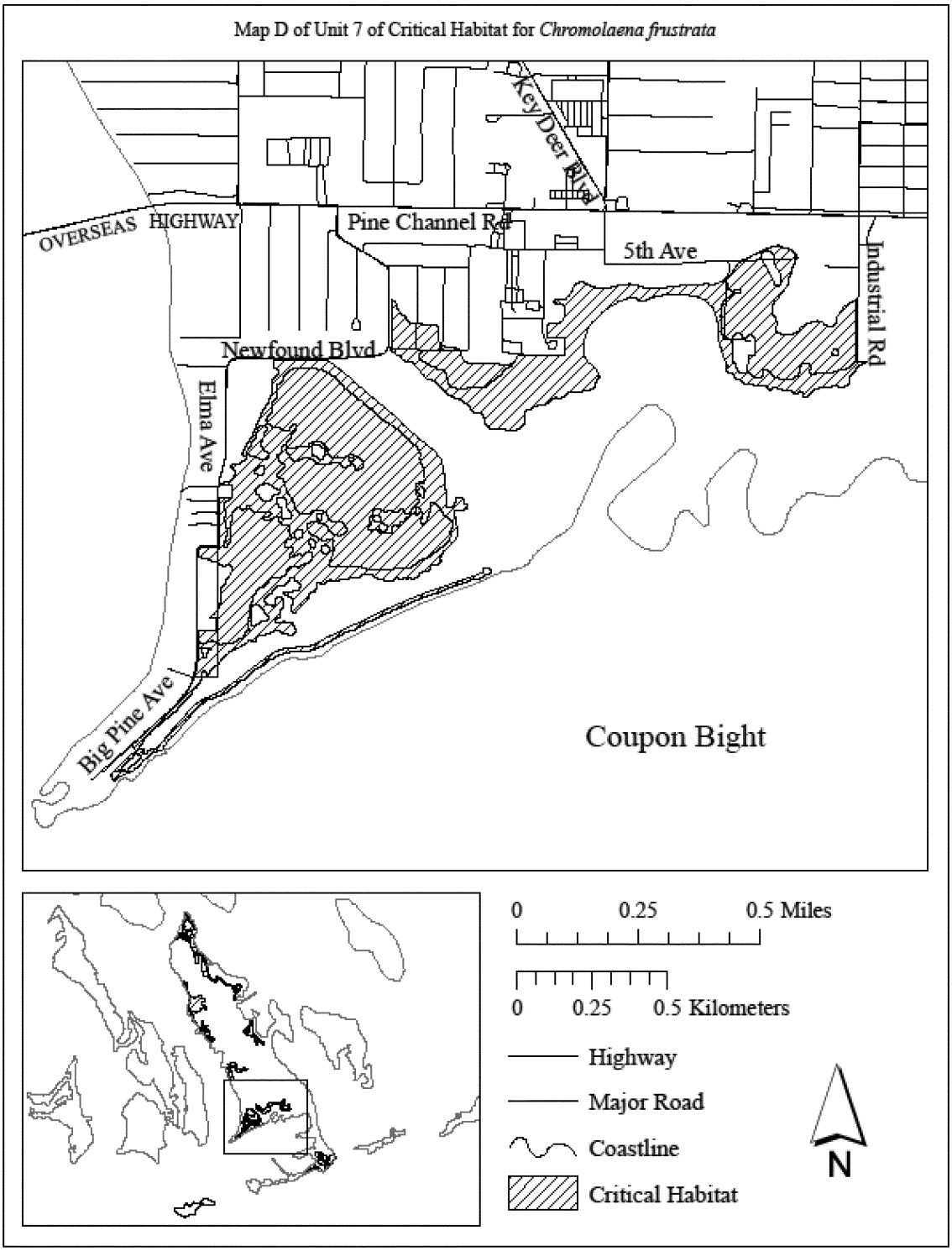
(iv) Map B of Unit 7 follows:



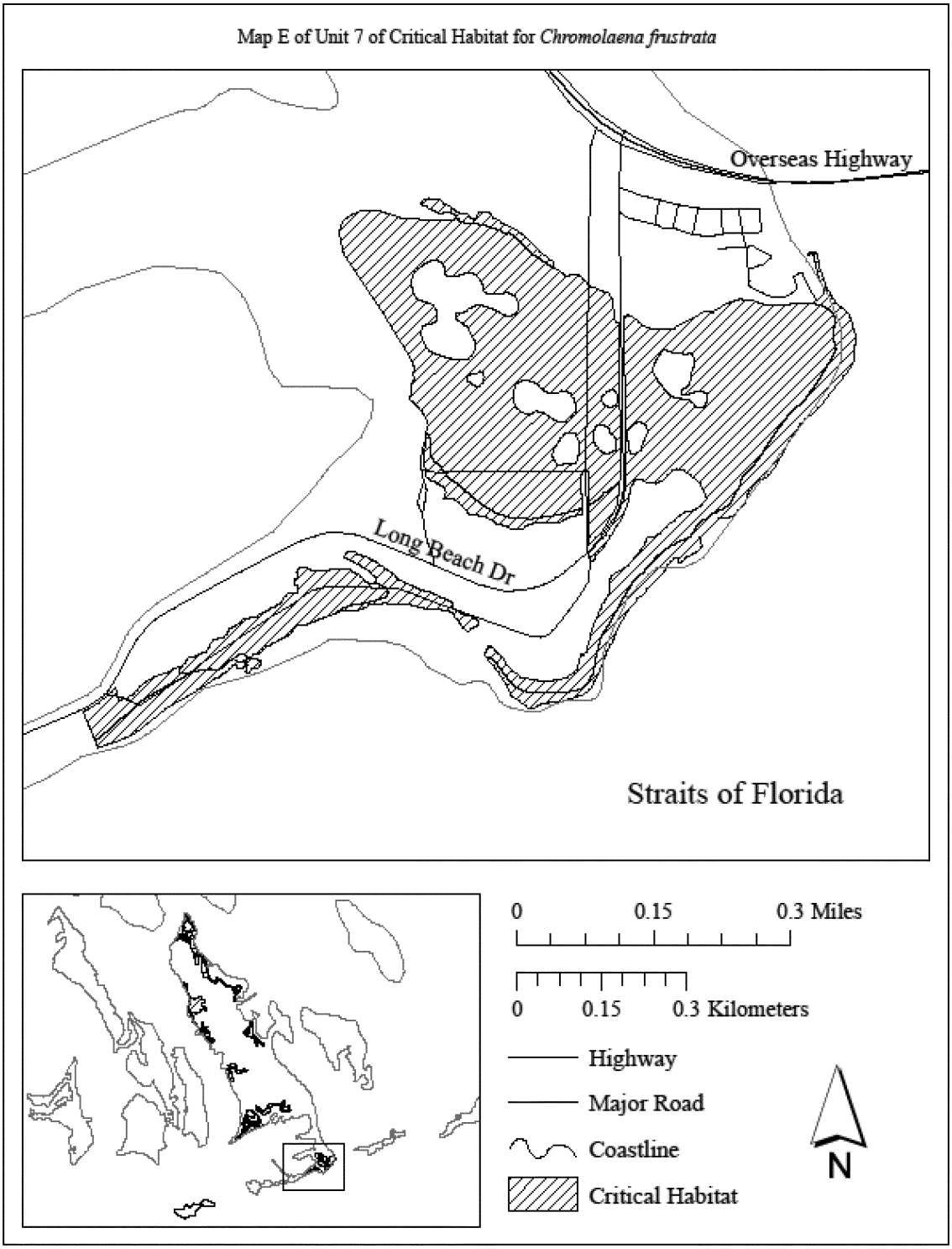
(v) Map C of Unit 7 follows:



(vi) Map D of Unit 7 follows:



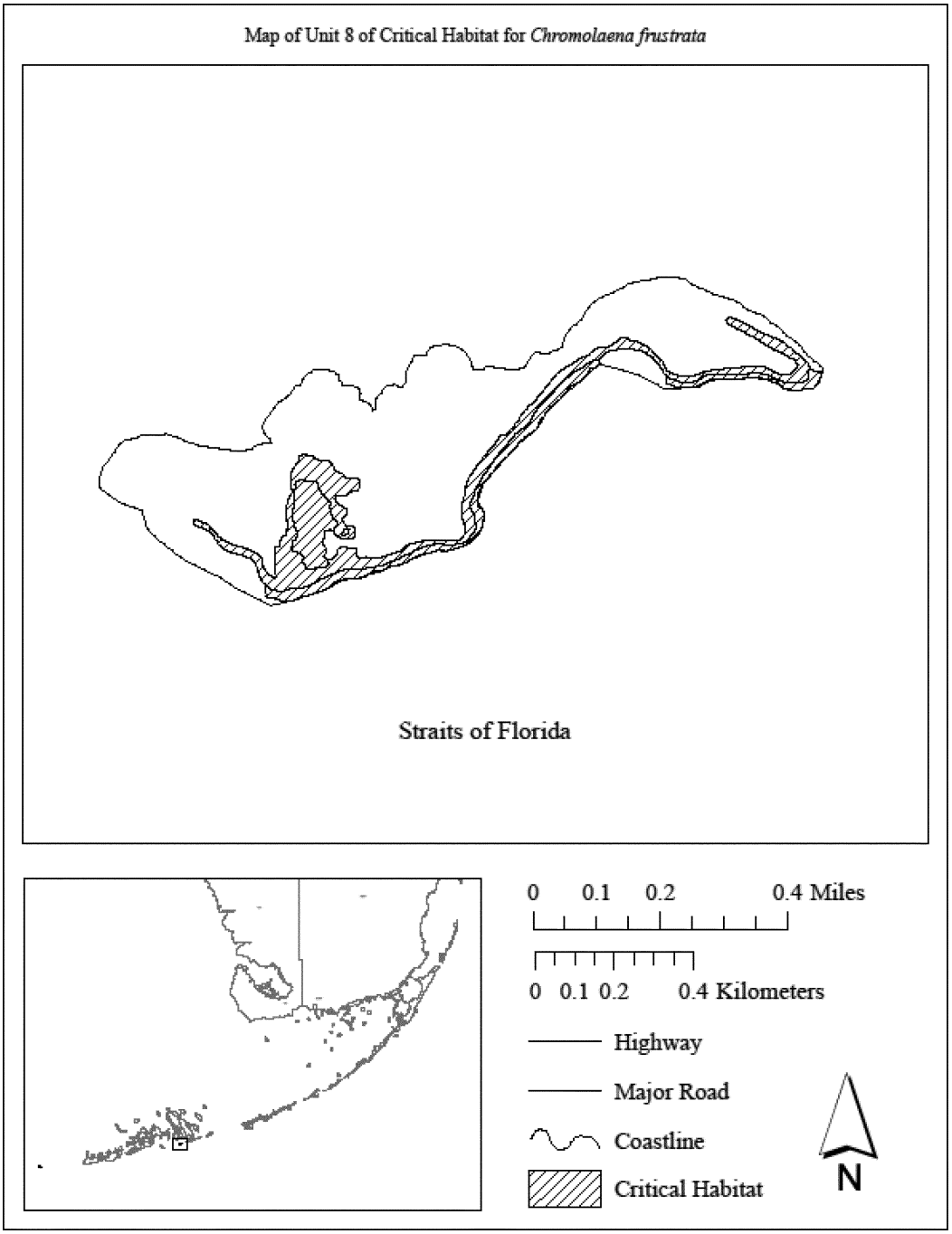
(vii) Map E of Unit 7 follows:



(13) Unit 8: Big Munson Island, Monroe County, Florida.

(i) *General Description:* Unit 8 consists of a total of 28 acres (11 hectares) in Monroe County. This unit is composed entirely of lands in private ownership.

(ii) Map of Unit 8 follows:

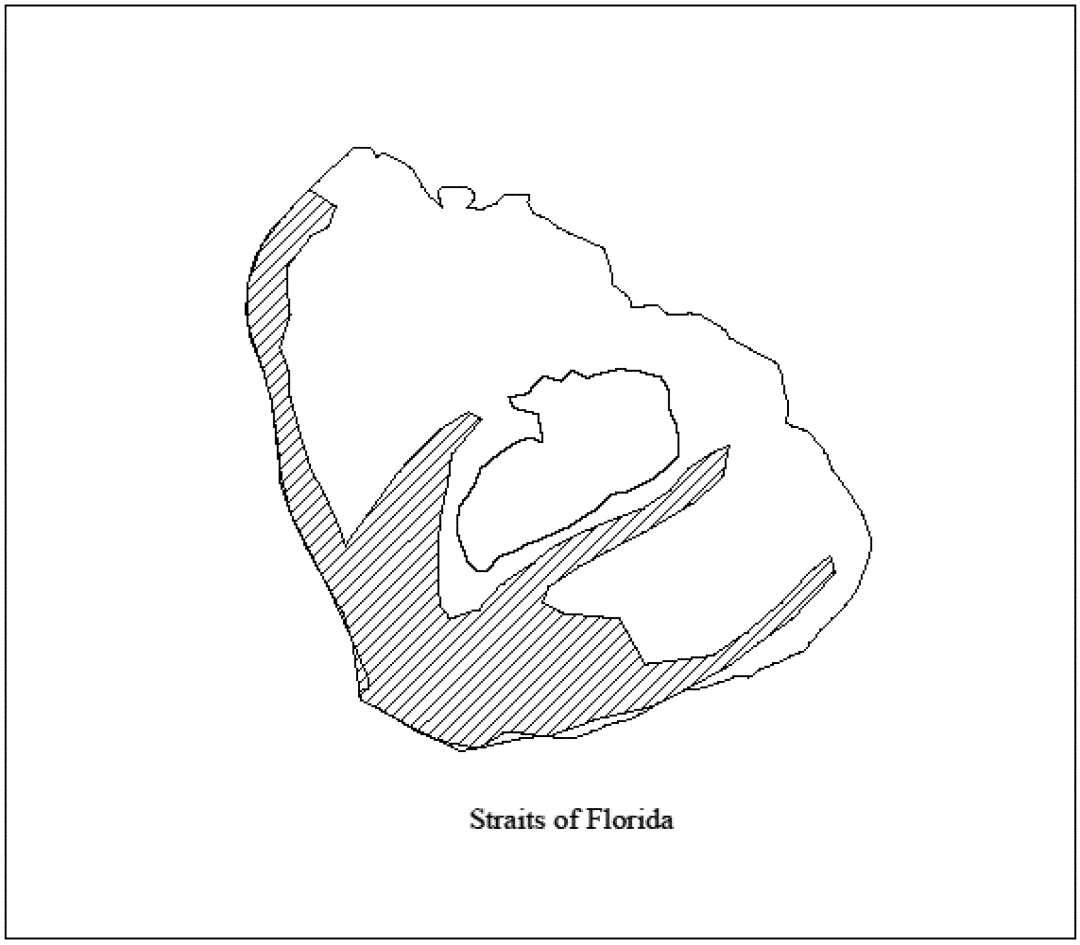


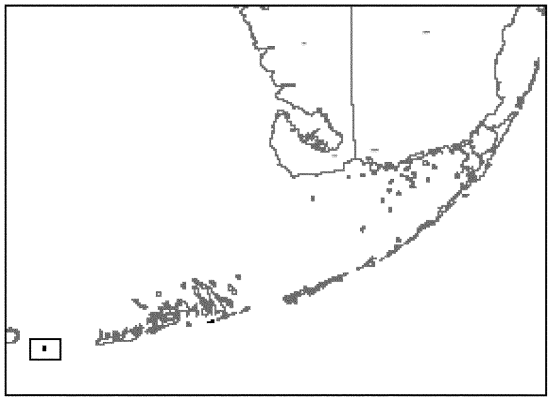
(14) Unit 9: Boca Grande Key, Monroe County, Florida.

(i) *General Description:* Unit 9 consists of a total of 62 acres (25 hectares) in Monroe County. This unit is composed entirely of lands in Federal ownership, 100 percent of which is located within the Key West National Wildlife Refuge.

(ii) Map of Unit 9 follows:

Map of Unit 9 of Critical Habitat for *Chromolaena frustrata*





0 0.1 0.2 0.4 Miles

0 0.1 0.2 0.4 Kilometers

Highway

Major Road

Coastline

Critical Habitat

N

* * * * *

Dated: December 20, 2013.

Rachel Jacobson,

Principal Deputy Assistant Secretary for Fish and Wildlife and Parks.

[FR Doc. 2013–31576 Filed 1–7–14; 8:45 am]

BILLING CODE 4310–55–C

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Wednesday, January 8, 2014

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